
very barrel Every shareholder Every day

nexen

# ANNUAL REPORT 2002

# Nexen Inc.:
# A Canadian-based global oil and gas and chemicals company

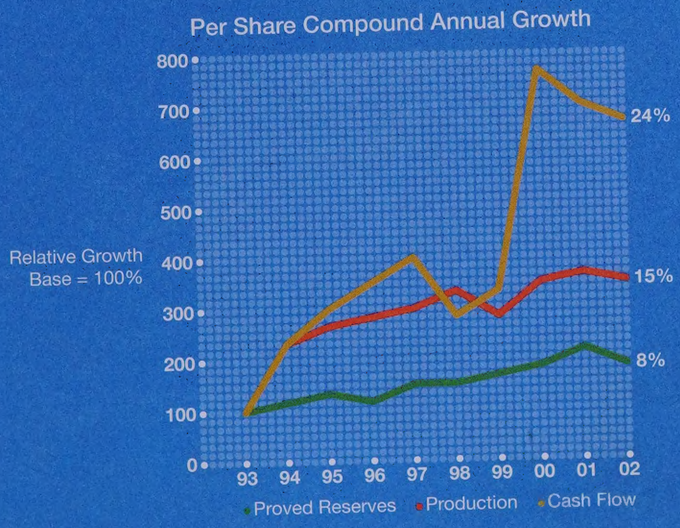
Imagine we gave you a world map and asked you to design a global oil and gas company. Where would you invest? The deep-water Gulf of Mexico? It's the best basin in the world today in terms of prospectivity, fiscal terms and infrastructure. The Middle East? You'll find huge reserves with low-cost development. Or the northern Alberta oil sands? Apply breakthrough technology to a vast resource, and you can create an attractive annuity-type asset.

As the cover shows, Nexen is in these and other attractive basins like West Africa, Colombia and Brazil. Today, we have development and exploration projects we expect will double our value over the next five years.

Our strategy is growth through the drill-bit, supplemented with strategic acquisitions when they make sense. We're good at the basics of exploration, development and exploitation and have a track record of delivering value throughout the business cycle. Our growth is supported by solid core assets in Canada, Yemen and the shallow-water Gulf of Mexico, as well as our chemicals business in North America and Brazil, where we produce bleaching agents for the pulp and paper industry.

Our goal is to create value by generating an attractive return on every dollar of capital we invest. This goes beyond increasing production. For us, creating value means long-term growth per share in reserves, production and cash flow—a strategy that benefits every shareholder.

# Value Matters




*Our growth from long-term projects is uneven, as we invest heavily up-front for production that materializes up to four years down the road. We expect continued value growth going forward as our major development projects contribute reserves, production and cash flow.*

# From the Gulf of Mexico: Major discoveries

PROSPECTIVE. PRODUCTIVE. PROFITABLE.

*The deep-water Gulf of Mexico offers large reserves, high flow rates, exploration success rates of one-in-four, excellent fiscal terms, rapidly developing infrastructure and proximity to the world's largest oil and gas market.*

Operating in the shallow-water Gulf since the 1980s, we used our knowledge and success to transition into deep water. In just five years, we've developed a strong and growing business in the deep water with strategic acquisitions, strong partnerships and astute exploration. Our first deep-water project, Aspen, shown on the right, came on-stream in December 2002—just 19 months after the initial discovery. We're ramping up production from two subsea wells and are producing more than 16,000 equivalent barrels (net to Nexen), with operating costs less than US$2 per boe. And that's just the beginning.

Gunnison, our second deep-water project, is on schedule for first production early in 2004. Fiscal terms for both projects are excellent, as production is royalty free on the first 87.5 million equivalent barrels. Estimated netbacks for Aspen and Gunnison are twice our corporate average, which means cash flow will grow faster than production, resulting in strong profitability. We also have other high-quality prospects in the deep water and deep Miocene gas projects on the shelf. Our plan is to explore aggressively, find more reserves to connect to existing infrastructure or justify stand-alone facilities in the basin, and triple our U.S. production, before royalties, to 100,000 boe per day by the end of 2006.

# Growing netbacks.

# In Canada:
# Massive bitumen resource

EMERGING LEADER IN THE ATHABASCA OIL SANDS

*Many people believe the Athabasca oil sands of northern Alberta are a key source of long-term energy supply for North America. We agree.*

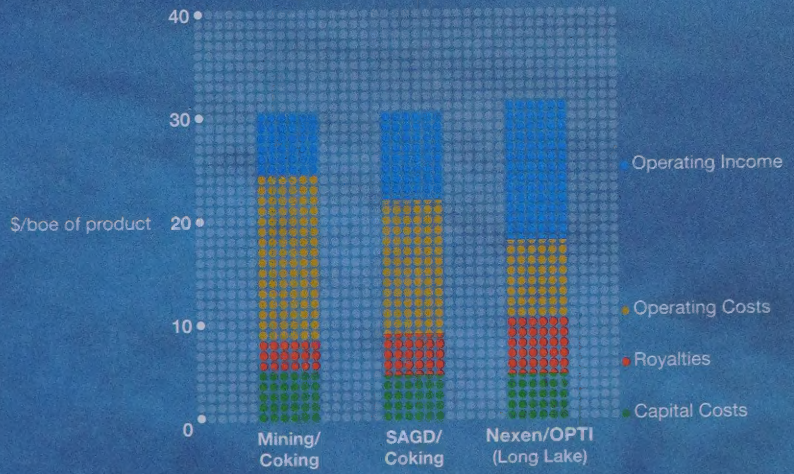
That's why we've captured a resource base of more than four billion barrels of recoverable bitumen and purchased proprietary access to a technology that upgrades low-value bitumen into a premium synthetic crude oil, at costs we believe are significantly lower than competing technologies.

The upgrading technology has been proven in a demonstration plant. It is efficient and robust. Now, at Long Lake, pictured on the right, we're pilot-testing steam assisted gravity drainage (SAGD) technology to extract bitumen. In 2003, we will continue detailed engineering and complete cost estimates for a synthetic crude oil project of 60,000 barrels per day and decide on commerciality by year-end. When commerciality is declared, facilities construction would begin in 2004, with bitumen SAGD production expected in 2006 and upgrader start-up in 2007.

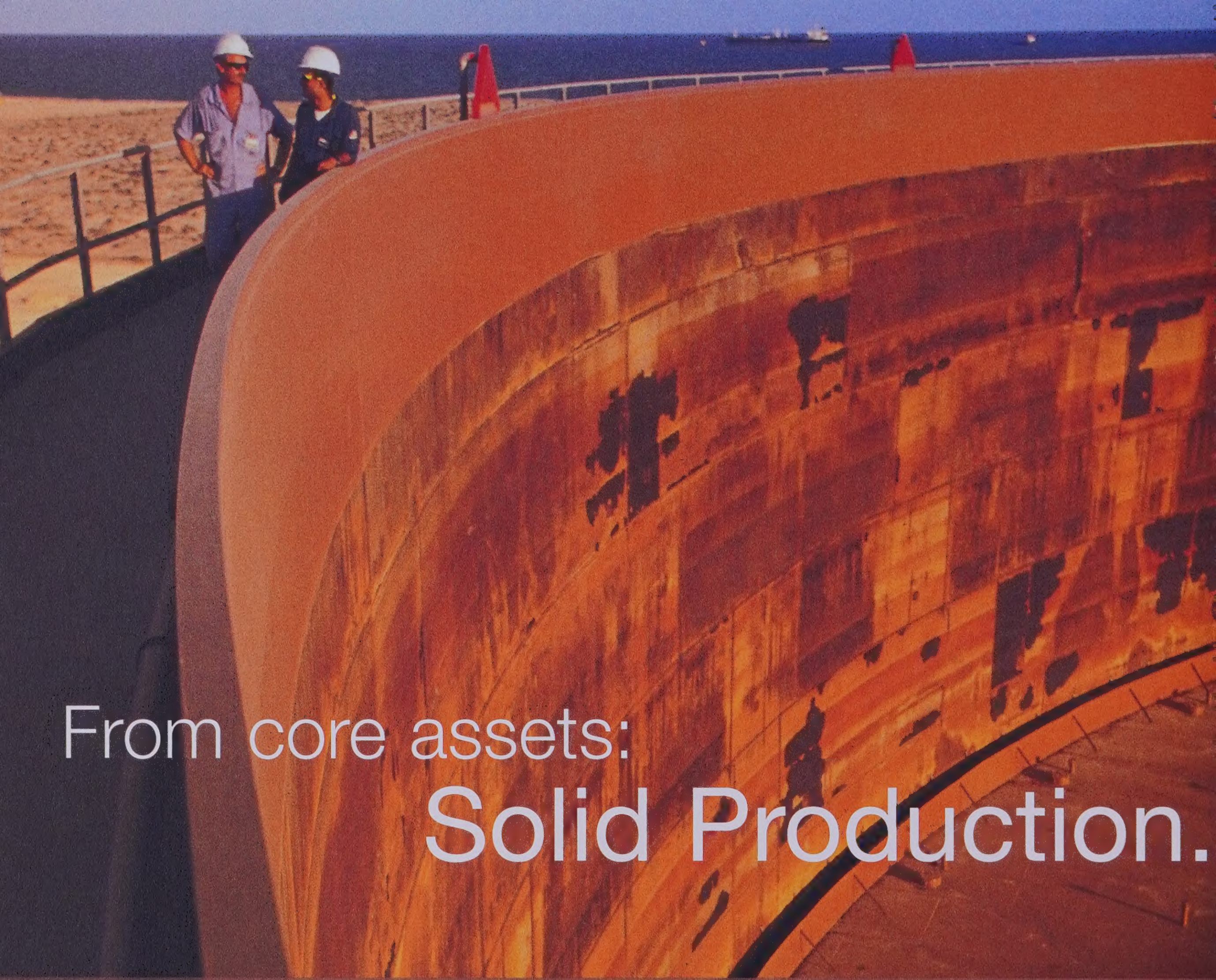
This project will dramatically change our company. Putting it in perspective, a four-billion-barrel recoverable resource would enable us to replace our entire 2002 production for 40 years. We're already planning beyond 2007, for future phases of this project. A legacy asset—generating steady production and free cash flow year after year—it's the perfect complement to our global exploration program.

# Breakthrough technology.

Comparing Technologies




*A premium-priced product and a process that uses asphaltine waste for fuel rather than natural gas are two key advantages that will enhance the value of our vast bitumen resource at Long Lake.*



# From core assets: Solid Production.

FUNDING OUR GROWTH

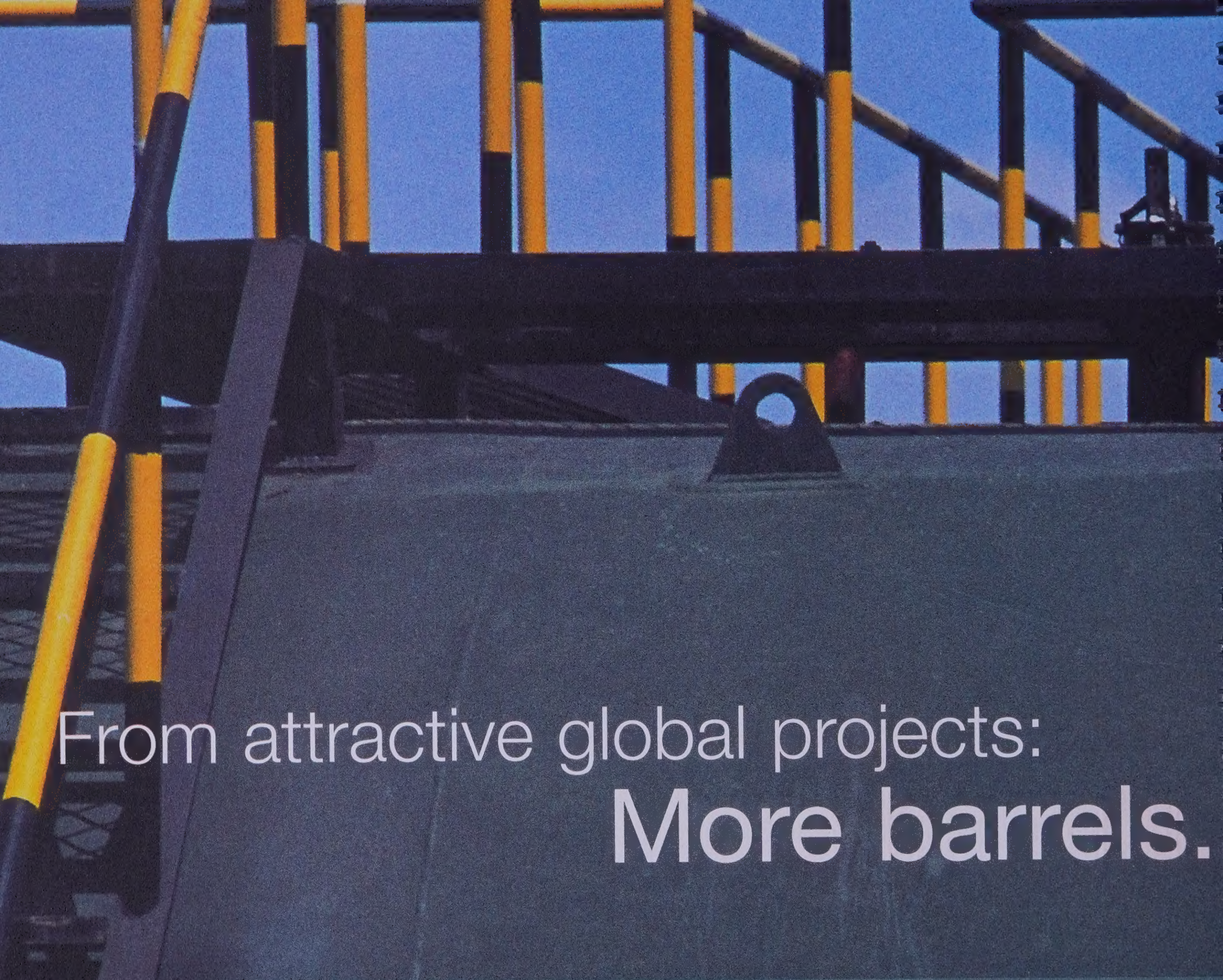
*Our ability to extract full value from our core assets, like the Masila fields in Yemen, sets us apart.*

In Yemen, we've discovered more than a billion barrels of oil since 1991, and we're still finding more. In fact, we've just added the new million-barrel tank you see here to store production awaiting tanker loadings. We've demonstrated superior operating skills, producing more than 230,000 gross barrels per day year after year, at around US$1.25 per barrel. We're recognized for our ability to work in harmony with local communities so they benefit from our presence, and our oil flows uninterrupted.

This same business model applies to our core operations in Canada and the shallow-water Gulf of Mexico. Because the cash flow generated from our core assets significantly exceeds their capital requirements, it can be used to support our exploration and development activities worldwide. However, we recognized some time ago that these assets are maturing, and we are proactive in managing production declines and operating costs to extract their maximum value. We're also testing technologies such as VAPEX enhanced oil recovery in our maturing assets, while transitioning to new opportunities like the oil sands, coal bed methane and the deep-water Gulf.

In 2002, our operations generated over $900 million more cash flow than the sustaining capital they required. That cash flow helped finance the development of Aspen, Gunnison, Guando, the Syncrude expansion and Premium Synthetic Crude project—our core assets of tomorrow.


Significant free cash flow.



# From attractive global projects:
# More barrels.

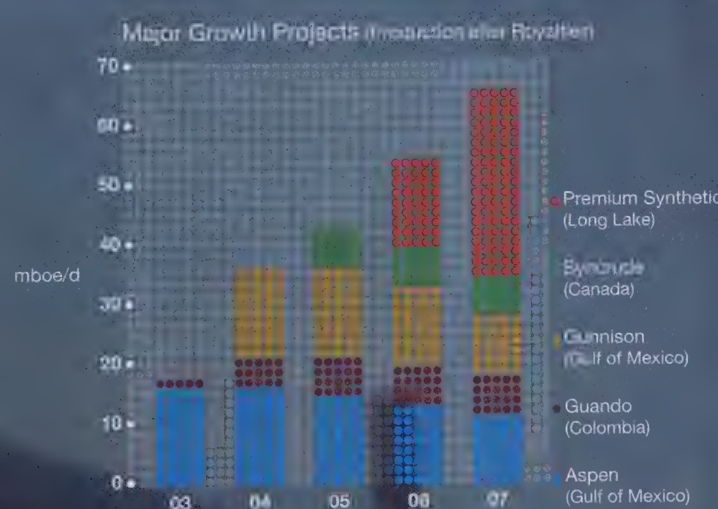
**DEVELOPING MORE VALUABLE BARRELS**

*Our inventory of quality development projects is significant and growing.*

In addition to Aspen and Gunnison in the deep-water Gulf and the Premium Synthetic Crude project in Canada's oil sands, we're developing the Guando field in Colombia highlighted here, and participating in the expansion at Syncrude, also in Canada's oil sands. Over the next five years, these five development projects are expected to add between 55,000 and 65,000 boe per day of production, after royalties, and will become core assets.

Why are we focusing on production net of royalties? Because net production adjusts for the different fiscal terms of each project. It's what we get after local governments take their share. Our major development projects have more attractive fiscal terms, with lower royalties, lower costs and higher returns. It's these more valuable barrels that will accelerate Nexen's growth going forward.

# Better margins.




*Near term, Aspen will spark our growth with about 15,000 boe/day, aided by volumes from Guando. Gunnison is expected on-stream in 2004 and Syncrude's Stage 3 expansion in 2005. By 2007, Long Lake should add about 30,000 barrels/day to our production.*

# From worldwide exploration: Potential for

FUELING LONG-TERM GROWTH

*Our opportunity portfolio totals about 8.5 billion equivalent barrels of unrisked resource potential. These opportunities are diversified yet focused.*

We're not dependent on any one area, play type, economic structure or political regime. And yet, when we're successful, we have the follow-up opportunities on surrounding acreage to grow rapidly.

In 2003, we plan to drill up to 18 high-potential wells and test 900 million equivalent barrels of resource. In the Gulf, we'll test deep-water prospects in Green Canyon and Garden Banks, where Aspen and Gunnison are located. And we'll test our deep-water Gotcha prospect in the Alaminos Canyon, and a deep Miocene gas prospect on the shelf. Gotcha has great potential, as it's adjacent to the recently discovered Great White prospect. In Nigeria, we'll finish appraising our Ukot and Usan discoveries to establish the viability of a commercial project. On the Northern Blocks of Yemen shown here, we'll continue interpreting seismic data and plan to drill at least one exploration well. Offshore Brazil, we will drill an exploration well on Block BC-20 in the Campos Basin. In Canada, we'll focus on gas prospects in northwestern Alberta and northeastern British Columbia.

The quality of our 2003 exploration program is our best ever as we're focusing on land offsetting existing discoveries and on play types we know well. This improves our chances for success and increases our expected returns.


step-change growth.

# From our financing strategy: Flexibility to

BUILDING LIQUIDITY AND FLEXIBILITY

*Our financing strategy is designed to support value creation throughout the commodity cycle by building liquidity and flexibility, so our balance sheet can weather fluctuations in commodity prices.*

As the chart on the right shows, this is exactly what we've done. With the 30-year financing we did in March, we have extended the average term to maturity, including preferred securities, to 26 years. Our unused committed lines of credit equal $1.6 billion, and our debt maturities over the next five years total approximately $613 million, an amount readily handled.

Our strong balance sheet allows us to manage our business smoothly and efficiently throughout the commodity cycle, with sufficient room to make the capital investments we need to grow. We have completed our initial capital investment in Aspen. Construction at Gunnison will be finished in 2003, and our Syncrude Stage 3 investment will be completed in 2005. These projects, along with our core assets, will contribute incremental cash flow to help fund our capital outlays for the Long Lake upgrader in the 2004 to 2006 timeframe.

# grow organically.

| FINANCIAL FLEXIBILITY & LIQUIDITY | Early 1998 | Year-end 2002 |
|---|---|---|
| LIQUIDITY | | |
| Unused committed capacity | $800 million | **$1.6 billion** |
| Average term to maturity | 5 years | **20 years*** |
| FLEXIBILITY | | |
| Bank debt as % of total debt | 74% | – |

* including preferred securities

# And from values that matter:
# Honesty. Ethics.

**THE VALUE IN VALUES**

*Our global reputation as a fair and ethical company is a key competitive advantage.*

The trust we've earned helps us realize the rewards from our multi-year growth projects. It helps us attract and retain talented employees whom we treat with respect. We're welcome in communities where we operate because we involve local people in decisions that affect them and develop mutually beneficial relationships. And our reputation helps us continue to secure the capital we need to grow.

In 1990, our Board of Directors was one of the first among Canadian oil and gas companies to create an Environment, Health and Safety Committee. In 1997, we were leaders in developing the International Code of Ethics for Canadian Business. We've also established sustainable business processes company-wide to minimize our impact on the environment. All employees attend integrity workshops so they understand our commitment to fair and ethical business practices. We believe living our values helps deliver value for shareholders.

*You can read about specific initiatives like our commitment to the United Nations Global Compact, Yemen scholarship program, Aboriginal relations program in Canada, community affairs program in Colombia and our proactive stand on Kyoto in our Sustainability Report. To receive a copy, please call 403.699.3097 or visit www.nexeninc.com.*


nexen
nexen
Integrity.


I'm confident our strategy will
continue to deliver

Nexen is a strong, profitable company. We're investing for the future and are on the threshold of accelerated success. Today, we're established in the best basins in the world with attractive projects that are transforming our company. I predict our results over the next five years will exceed those of the past. Charlie Fischer, President and CEO

# value for shareholders.

| | **2002** | 2001 | 2000 |
|---|---|---|---|
| Strong Earnings ($/share) | **3.34** | 3.40 | 4.52 |
| Reliable Cash Flow ($/share) | **10.71** | 11.20 | 12.01 |
| Record Capital Investment ($millions) | **1,625** | 1,404 | 915 |
| Solid Reserve Replacement, net of dispositions (%)(1) | **104** | 137 | 140 |
| Annual F&D Costs ($/boe)(1) | **13.63** | 9.47 | 6.31 |
| Competitive Five-year F&D Costs ($/boe)(1) | **7.25** | 6.13 | 5.71 |
| Growing Production (mboe/d) | **269** | 268 | 256 |

(1) Based on proved reserves before royalties, using forecasted prices.

**Fellow Shareholders:** Nexen has been consistently successful for over 30 years. Why? Because we manage Nexen as a business first and an oil and gas company second. This means we think strategically and act opportunistically. We base our decisions on value criteria rather than just volume criteria. And we focus on low-cost organic growth over high-cost acquisitions.

Many achievements in 2002 confirm the success of this model. We delivered strong financial results, while pursuing our largest capital program ever. We advanced new projects in the deep-water Gulf of Mexico, Canadian oil sands and internationally, while managing maturing assets in Western Canada and the U.S. Gulf shelf.

**For me, the highlight of the year** was the completion of Aspen, our first deep-water development project in the Gulf of Mexico. Aspen is a significant milestone. It shows how we strategically positioned ourselves in one of the world's most attractive basins and then acted opportunistically, increasing our ownership in Aspen from 20% to 60% to gain a larger share of this great project and ensure its timely development. In less than four years, we've built a strong position in the deep-water, with major discoveries and a large exploration inventory. Aspen is producing, and a second field, Gunnison, will come on-stream early in 2004.

## We're well positioned in

Every barrel from Aspen and Gunnison will be twice as valuable as our corporate average, as prolific wells and royalty-free production generate high cash netbacks. We'll see outstanding returns from these projects.

**In 2002, our F&D costs increased** to $13.63 per boe, reflecting the nature of our capital program. Two-thirds of our capital was invested in multi-year growth projects that typically experience higher F&D costs in the early stages as we invest capital, yet book few or no reserve additions. For example, we invested $60 million in our Premium Synthetic Crude project at Long Lake, yet only booked 1.5 million proved reserves for the pilot project. We haven't booked any proven or probable reserves in Nigeria even though the Usan/Ukot discoveries look very promising. Almost 70% of our proved reserve additions were in the Gulf of Mexico and Yemen, where we're generating very attractive returns that can support higher F&D levels. In Yemen, cost recovery mechanisms enable us to incur F&D costs higher than our netback, yet still make very attractive full-cycle returns. While the increasing maturity of some of our conventional Canadian assets put pressure on 2002 F&D costs, less than 15% of our total capital was invested here. Our core assets continued to generate substantial free cash flow to fund future growth projects. Overall, our returns from our 2002 investment program exceeded our cost of capital, and this will continue over the long term.

**Our greatest challenge in 2002** was our limited production growth, despite good performance from infill drilling at Buffalo offshore Australia and at Ejulebe, offshore Nigeria. Our North American production was stressed by bad weather, program delays and lower productivity from increasingly mature assets in Canada and the shelf of the Gulf of Mexico. This maturity is affecting the industry in general, as it is more difficult and expensive to grow production here. We have already adapted to this challenge. We are investing in new technologies like VAPEX oil recovery, which may enhance the life of our heavy oil reserves, much the same as horizontal drilling did a decade ago. We are also building a strong land position and pilot testing coal bed methane production that has low-risk, long-life reserve characteristics, similar to our shallow gas properties. More importantly, we're limiting our investment in maturing properties to maximize their value, and reinvesting much of the cash flow they generate into new, more attractive projects.

**The transition to new sources of production** will span several years. The good news is we've completed most of the upfront work. We're already firmly established in four very strategic, opportunity-rich basins. We're in the Middle East, which provides low-cost profitable production. We're in the Canadian oil

## the world's best basins,

sands, with access to long-life reserves, and we're in the deep-water Gulf of Mexico and offshore Nigeria, with opportunities for step-change production growth. In each basin, we can point to tangible projects that offer more valuable production. Although our gross production will grow modestly as our basin mix shifts, our cash flow growth will be strong. In 2003, we expect production after royalties to grow between 6% and 10% over 2002. Assuming similar prices year-over-year, cash flow in 2003 should jump 14%. That's the benefit of a more valuable barrel—it contributes more to the bottom line.

**We are very excited about our position** in the Athabasca oil sands. In addition to our Syncrude interest, we control a 4-billion barrel recoverable resource in the area—enough to replace Nexen's current oil and gas production for over 40 years. We understand the economic drivers of this business. With our Premium Synthetic Crude project at Long Lake, we have proprietary access to the lowest operating cost technology to produce and upgrade in-situ bitumen into premium synthetic crude oil. We made significant progress in 2002 and built a strong project team. In 2003, we expect to advance through the design and approval phases. Following a decision on commerciality late in the year, we expect to begin construction in 2004 for bitumen SAGD production in 2006 and upgrader start-up in 2007.

In the Middle East, Yemen continues to meet its production targets, and is on track for similar results in 2003. This asset has exceeded expectations and provides further opportunities with our large land position on the Northern Blocks. Our other assets are also performing well. We began commercial development of Guando in Colombia in 2002 and expect it to reach peak production in 2005. We also expect to finish delineating our Usan and Ukot discoveries offshore Nigeria in 2003 and establish the viability of a commercial project.

In 2002, our marketing group did an outstanding job in a year when many of our competitors withdrew from the market. This has created opportunities to increase our fee-for-service business and strengthens our position for low-risk growth. And on the Chemicals side, we completed our plant expansions in Manitoba and Brazil on budget and ahead of schedule, with both making positive financial contributions.

I congratulate Nexen's employees, as our achievements take creativity, skill and determination. I believe strongly in our organic growth strategy because we have the talent and opportunities to fuel Nexen's growth. Our employees share my enthusiasm. Once again, we were chosen as one of the 50 best companies to work for in Canada by *Report on Business* magazine, based on feedback from our employees.

## with the people, technology and

**At Nexen, operating with integrity** applies to every action, every day, with every stakeholder. For me, good governance has always made good business sense. Over the past year, investors and the public have been shaken by company scandals. This has led to recent regulatory changes to improve the quality of disclosure and governance practices, which we welcome. In fact, we've followed many of the recommendations of the *Sarbanes-Oxley Act* and the TSX task force for years. For example, our strong, largely independent Board and Audit Committee represent our shareholders' interests without bias. In December, we welcomed Thomas O'Neill to our Board of Directors, whose accounting and audit expertise will contribute significantly to our diverse Board. Our strong internal controls, disclosure procedures and risk management tools contribute to quality financial reporting. The International Code of Ethics, which we helped develop in 1997, and our Ethics Policy guide us in honest, ethical decision-making. And our reserves, the foundation of value in our industry, are reviewed by third parties and approved by our Board of Directors. I assure you we are committed to leading-edge practices in corporate governance.

**We have an unwavering commitment to the environment** and, as a long-term player in this industry, we seek to minimize the environmental impact of our operations. Rising concentrations of greenhouse gases have become an important global issue. In Canada, we have been actively engaged in

reducing our greenhouse gas emissions for some time. Over the past five years, we've reduced emissions by 1.9 million tons of $CO_2$ equivalent. In 2002, Nexen and other Canadian companies, industries and provincial governments spoke out against the Kyoto Protocol because we believe its implementation will not significantly reduce global emissions and could put Canadian-based industries at a competitive disadvantage compared to our major trading partners. We made the Government of Canada aware of these concerns, and they assured us that no industry or region will be unfairly affected. The Government ratified Kyoto in December and outlined the maximum costs per unit of production for our industry. Although further clarification is needed, we will work to ensure the cost of compliance will not significantly impair the economic returns from our oil sands project and existing business. We continue to look for ways to cost-effectively reduce emissions from our facilities worldwide, work with all stakeholders and be a positive force in the growth of an industry that's so important to Canada's economy.

**I'm excited about Nexen's future,** as every day I see the value we are creating for shareholders. I'm confident our strategy will continue to deliver long-term value growth, because we're doing the right

## opportunities to fuel our growth.

things for the right reasons. We continue to focus on growth through the drill-bit and explore in areas where our chances for success have improved. We're investing in new technologies that increase value and position us as industry leaders. We continue to invest in people as we develop skills to manage mature assets and re-deploy resources into our new growth areas. We have the projects to ensure continued success and a balance sheet to support growth despite fluctuations in commodity prices. We have an exceptional Board of Directors whom I thank for their excellent governance and strategic guidance.

Within five years, new long-life assets will further solidify our company's foundation. Significant production from legacy assets like Long Lake, Syncrude and Chemicals will complement our production in Yemen, Colombia and West Africa. We will be established deep-water operators. And, most important, every barrel from our new assets will be more valuable than the one it replaces, creating significant, real value for every shareholder.

**Charlie Fischer, President and CEO,** February 24, 2003

Inspired by shared values,

we're as diverse as the

communities we work in.

# For more details, see the 10K & historical review

WE'LL HELP YOU NAVIGATE.

OUR OPERATIONS



OUR PERFORMANCE



OUR CORPORATE GOVERNANCE

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

**FORM 10-K**

**ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) of THE SECURITIES EXCHANGE ACT OF 1934**

**For the year ended December 31, 2002**

**Commission File Number 1-6702**

# NEXEN INC.

**(Formerly Canadian Occidental Petroleum Ltd.)**

Incorporated under the Laws of Canada

98-6000202
(I.R.S. Employer Identification No.)

801 – 7th Avenue S.W.
Calgary, Alberta, Canada T2P 3P7
Telephone - (403) 699-4000
Web site - www.nexeninc.com

**Securities registered pursuant to Section 12(b) of the Act:**

| Title | Exchange Registered On |
|---|---|
| Common shares, no par value | The New York Stock Exchange |
| | The Toronto Stock Exchange |
| Preferred Securities, due 2047 | The New York Stock Exchange |
| Preferred Securities, due 2048 | The New York Stock Exchange |

**Securities registered pursuant to Section 12(g) of the Act:** None.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days. Yes _√_ No______

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).
Yes _√_ No______

On January 31, 2003, the aggregate market value of the voting shares held by non-affiliates of the registrant was approximately Cdn $4.1 billion based on the Toronto Stock Exchange closing price on that date. On January 31, 2003, there were 123,123,189 common shares issued and outstanding.

## TABLE OF CONTENTS



Unless we indicate otherwise, all dollar amounts ($) are in Canadian dollars, and production and reserves are our working interest after royalties.

Below is a list of terms specific to the oil and gas industry. They are used throughout the Form 10-K.

| | | | | | |
|---|---|---|---|---|---|
| /d | = | per day | mboe | = | thousand barrels of oil equivalent |
| bbl | = | barrel | mmboe | = | million barrels of oil equivalent |
| mbbls | = | thousand barrels | mcf | = | thousand cubic feet |
| mmbbls | = | million barrels | mmcf | = | million cubic feet |
| mmbtu | = | million British thermal units | bcf | = | billion cubic feet |
| km | = | kilometre | WTI | = | West Texas Intermediate |
| | | | NGL | = | natural gas liquid |

Oil equivalents are used to compare quantities of natural gas with crude oil by expressing them in a common unit. To calculate equivalents, we use 1 bbl = 6 mcf of natural gas.

The noon-day Canadian to US dollar exchange rates for Cdn $1.00, as reported by the Bank of Canada, were:

| (US$) | December 31 | Average | High | Low |
|---|---|---|---|---|
| 1998 | 0.6534 | 0.6743 | 0.7105 | 0.6343 |
| 1999 | 0.6929 | 0.6730 | 0.6929 | 0.6537 |
| 2000 | 0.6666 | 0.6733 | 0.6973 | 0.6413 |
| 2001 | 0.6279 | 0.6458 | 0.6695 | 0.6241 |
| 2002 | 0.6331 | 0.6369 | 0.6618 | 0.6199 |

On January 31, 2003, the noon-day exchange rate was US $0.6540 for Cdn. $1.00.

## PART I

### Items 1 and 2. Business and Properties

#### BACKGROUND

Nexen Inc. (Nexen, we or our) is a global energy and chemicals producer incorporated under the laws of Canada. Our history is set out below:

| Date | Event |
|---|---|
| July 12, 1971 | We were formed under the name Canadian Occidental Petroleum Ltd. (COPL) through a reorganization by Occidental Petroleum Corporation (Occidental) of Los Angeles, California, which combined the crude oil, natural gas and sulphur operations of its 55% owned subsidiary, Jefferson Lake Petrochemicals of Canada Ltd., and the operations, including chemicals, of its wholly owned subsidiary, New Hooker Canada Ltd. |
| May 20, 1983 | We purchased Canada-Cities Service, Ltd. (Cities Service) for $354 million. The acquisition doubled our size, while substantially increasing reserves and revenues partly through a 13.23% interest in the Syncrude Project. COPL and Cities Service amalgamated and continued under the name COPL on January 1, 1984. |
| February, 1984 | We acquired Cities Offshore Production Co., a company that held interests in producing oil and gas fields in the Gulf of Mexico, offshore Louisiana, for US$132.5 million. |
| May 31, 1988 | We purchased Moore McCormack Energy, Inc. a company with mostly onshore operations in Texas, Louisiana and Alabama. |
| | During 1988 we sold 6% of the interest we acquired in Syncrude through the Cities Service acquisition for approximately $330 million. We retained a 7.23% interest. |
| April 14, 1997 | We acquired Wascana Energy Inc. (Wascana) as a result of a take-over bid. The total purchase price for Wascana was approximately $1.7 billion. Wascana became a wholly-owned subsidiary as a result of an amalgamation on June 30, 1997. |
| April 17, 2000 | We entered into an agreement with Ontario Teachers' Pension Plan Board (Teachers) and Occidental where Occidental sold its 29% interest in COPL, which was approved by a majority of shareholders other than Occidental or Teachers. Teachers purchased 20.2 million common shares, we repurchased the remaining 20 million common shares for $605 million including associated fees, and exchanged our oil and gas operations in Ecuador for Occidental's 15% interest in our chemicals operations. |
| November 2, 2000 | Further to the sale of Occidental's interest we changed our name to Nexen Inc. |

Electronic copies of our filings with the Securities Exchange Commission (from November 8, 2002 onward) are available, free of charge, on our website (www.nexeninc.com). Filings prior to November 8, 2002 are available free of charge, upon request, by contacting our investor relations department at (403) 699-5931.

## OPERATIONS

Nexen has operations in four main areas:

- Conventional Oil and Gas
- Synthetic Crude Oil
- Oil and Gas Marketing
- Chemicals

For financial reporting purposes, these areas are defined as reportable segments. Conventional oil and gas is further broken down into geographic segments. Information on revenues, operating profit, capital expenditures and identifiable assets for these segments for the past three years appears in note 15 to the Consolidated Financial Statements and in Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report.

### Conventional Oil and Gas

We explore for, develop and produce conventional crude oil, natural gas and related products around the world. Our core assets are located in western Canada, the United States (US) Gulf of Mexico and Yemen, with other producing properties offshore Australia and Nigeria and onshore in Colombia. We are developing new growth opportunities in Colombia, Nigeria, and Brazil. We generally manage our operations on a country-by-country basis reflecting differences in the regulatory environments and risk factors associated with each country. The oil and gas industry is highly competitive and this is particularly true when searching for, and developing, new sources of supply, and in constructing and operating crude oil and natural gas pipelines and facilities.


Crude oil and natural gas commodities are sensitive to numerous worldwide factors and are generally sold at contract or posted prices. Changes in world crude oil and natural gas prices may significantly affect our net income and cash generated from operating activities. Consequently, these prices may also affect the carrying value of our oil and gas properties and our level of spending for oil and gas exploration and development.

We have a broad customer base for our crude oil and natural gas. Alternative customers are generally available, therefore, the loss of any one customer is not expected to have a significant adverse effect. Oil and gas operations are generally not seasonal, except for heavy oil differentials that tend to be narrower in the summer months.

Our growth comes primarily through the drill bit, supplemented with strategic acquisitions. This ensures consistent, low-cost growth. We are focused on maximizing value, not volumes. Not all barrels have the same value so we also focus on capturing high value barrels which provide high netbacks. Our future growth will come from the deep-waters of the Gulf of Mexico, the Athabasca oil sands, the Middle East and offshore West Africa. The basins in these areas offer an optimal combination of prospectivity, attractive fiscal terms and low costs. Technical innovation is a key part of our value growth strategy and we are

investing in low cost bitumen upgrading, solvent extraction of heavy oil, coal bed methane, steam assisted gravity drainage and deep-water operating technology.

**Yemen**


| **Acreage** (thousand acres) | Developed | Undeveloped | Total |
|---|---|---|---|
| Gross | 38 | 20,150 | 20,188 |
| Net | 20 | 10,365 | 10,385 |

| **Proved Reserves** (mmbbls) | Before Royalties | After Royalties |
|---|---|---|
| Masila Block | 183 | 100 |

| **2002 Production** (mbbls/d) | Before Royalties | After Royalties |
|---|---|---|
| Masila Block | 118.0 | 55.8 |

Yemen's Masila Project (the Project) represented about 36% of our cash flow in 2002. Our strategy in this country is to maintain high production rates from the Masila fields, fully exploiting the project's remaining potential, while testing our exploration portfolio of over 20 million acres of undeveloped land for additional accumulations of hydrocarbons.

***Masila Block***

We have a 52% working interest in and operate the Masila Project. The Masila Project is the largest single source of oil production in Yemen and has grown steadily since discovery in 1990. To date, the 15 fields that comprise the Project have produced over 665 million gross barrels of oil from total gross recoverable reserves of just over one billion barrels. Nexen has the right to produce oil from the Masila fields until 2011 and the right to negotiate a five-year extension.

During 2002, $402 million ($209 million net) was invested to drill and equip 74 new development wells and expand existing infrastructure. Gross production was maintained throughout the year at approximately 226,900 barrels per day, net of fuel use.

Currently the majority of crude oil production comes from the Upper Qishn formation. Oil has been identified in formations below the Upper Qishn including the Lower Qishn, Upper Saar, Saar, Madbi, Basal Sand, and Basement formations. In 2002, waterfloods in three fields were implemented to develop reserves in a number of these formations. Waterfloods will be expanded in these and other fields in 2003.

Production from the Masila Project is governed by a Production Sharing Contract between the Government of Yemen and the Masila joint venture partners including Nexen (Partners). Under the terms of the contract, production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all of the Project's exploration, development and operating costs which are funded by the Partners. Costs are recovered from a maximum of 40% of production each fiscal year, as follows:

| **Costs** | **Recovery** |
|---|---|
| Operating | 100% in year incurred |
| Exploration | 25% per year for 4 years |
| Development | 16.7% per year for 6 years |

The remaining production is profit oil that is shared between the Partners and the Government on a sliding scale based on production rates. The Partners' profit oil share ranges from 20% to 33%. The Government's share includes provision for Yemen income taxes payable by the Partners at a rate of 35%. In 2002, the Partners' share of production from the Masila Project, including recovery of past costs, was approximately 33%.

The economics of Masila production are attractive. Historic finding and development costs are approximately US $2 per barrel and operating costs have averaged US $1 per barrel, resulting in excellent returns for shareholders. In addition, the structure of the contract moderates the impact on the Partners' cash flows during periods of low prices.

Yemen crude oil is sold based on reference prices, generally Dated Brent crude oil (Brent), adjusted for transportation and quality. West Texas Intermediate (WTI) normally trades at a premium to Brent, but the differential can vary during the year. As the demand for Brent crude oil increases relative to WTI the differential narrows, increasing the price of Brent on a relative basis. During 2002, we sold our Masila crude oil for an average discount of US $1.41/bbl to WTI.

### *Exploration Blocks*

We are actively exploring outside the Masila Block. We hold interests in seven exploration licenses comprising over 20 million acres of undeveloped land, the majority of which are located in northeastern Yemen close to the Saudi Arabian border. These blocks are governed by production sharing agreements that have similar fiscal terms to the Masila Project.

BLOCK 50

We successfully farmed-out a portion of Block 50. A new partner is currently funding an exploration program to earn an interest in the block. At the end of the program our working interest will be 31.667%. We are currently evaluating 1,683 kilometres of 2D seismic acquired in the third quarter of 2002. Depending on the results of this work, an exploration well may be drilled in 2003. To date, all commitments have been fulfilled on this block.

BLOCK 51

Nexen has an 87.5% working interest in Block 51. We have participated in three dry holes on the block. There is one remaining well commitment prior to block expiry in October 2004. At this time we have not budgeted for any capital spending on Block 51 for 2003, beyond annual fees.

NORTHERN BLOCKS

The Northern Blocks comprise five large exploration blocks (11, 12, 36, 54 and 59) that cover almost 13 million acres. They are located 250 km north of Masila in an undeveloped frontier area bordering Saudi Arabia. We currently have a 57% working interest on these blocks, except for Block 59 where we have a 55.8% working interest. In 2002, an exploration well, Al Mawarid-1, was drilled on Block 59. Although commercial quantities of hydrocarbons were not encountered, the well provided valuable information to calibrate our seismic data and to refine our geologic models for the region. In the third quarter of 2002, Nexen received one-year extensions for Blocks 11, 12, 36, and 54, which were initially due to expire in February 2003. This extension period will allow us to conduct further technical work to evaluate the potential of the region.

## Canada


| **Acreage** (thousand acres) | Developed | Undeveloped | Total |
|---|---|---|---|
| Gross | 968 | 2,870 | 3,838 |
| Net | 768 | 1,744 | 2,512 |

| **Proved Reserves** | Before Royalties | After Royalties |
|---|---|---|
| Crude Oil and NGLs (mmbbls) | 191 | 156 |
| Natural Gas (bcf) | 618 | 524 |
| Total (mmboe) | 294 | 243 |

| **2002 Production** | Before Royalties | After Royalties |
|---|---|---|
| Light Oil (mbbls/d) | 25.8 | 19.4 |
| Heavy Oil (mbbls/d) | 30.5 | 24.0 |
| Natural Gas (mmcf/d) | 167 | 128 |
| Total (mboe/d) | 84.1 | 64.7 |

Our strategy in Canada is to maximize value from our core operations while we actively pursue emerging sources of supply in the western Canadian sedimentary basin. These operations provide steady cash flow and earnings from our established portfolio of light oil, heavy oil, and natural gas assets. We are advancing three promising initiatives for future growth in our conventional activities: high impact gas exploration, coal bed methane development and enhanced recovery technology. Our exploration program targets high productivity deep gas plays in northeast British Columbia and the foothills of Alberta. We have a coal bed methane extraction pilot in central Alberta, and we are testing enhanced oil recovery techniques on our heavy oil fields.

### *Light Oil*

We are the largest producer of light oil in southeast Saskatchewan where we have a substantial land position in the Williston Basin. Production from the area is characterized by medium depth, Mississippian age light oil. In 2002, 51 oil wells were drilled on our lands. In 2003, we will sustain our operations through selective development of our properties with horizontal drilling.

We continue to focus on the development and full exploitation of our Hay property in northeast British Columbia. We discovered Hay in 1997 and brought production on stream in April 2000; it is now the largest producing oil field in British Columbia. In 2002, we produced our five millionth barrel from the field and drilled 30 wells to increase productivity at low cost. In 2003, we will add producing development wells to further exploit the existing pool. With the 2003 program, we plan to expand the existing water-handling capacity as well as drill vertical wells to test the pool boundaries.

### *Heavy Oil*

There is a significant number of large heavy oil fields in western Canada and, typically, finding costs for heavy oil are lower than for light oil. Heavy oil is characterized by high specific gravity or weight, and high viscosity or resistance to flow. Because of these features, heavy oil is more difficult to extract, transport and refine than other types of oil. Additionally, heavy oil reservoirs typically have lower recovery factors than conventional oil reservoirs providing the opportunity for increased recovery with the application of new technology. We are testing a number of different technologies to increase oil recovery factors on our existing properties. Heavy oil yields a lower price relative to light oil, because a smaller percentage of high value petroleum products can be refined from a barrel of heavy oil than from a barrel of higher quality crude without expensive refinery conversion capacity.

Our heavy oil operations are located in west central Saskatchewan. A strong focus on finding and operating costs is fundamental to maximizing heavy oil returns. Our large production base and existing infrastructure are important factors in managing these costs. In 2002, a total of 51 heavy oil wells were drilled and brought on production. A key success for heavy oil will be the development of new technology to increase oil recovery.

### *Natural Gas*

Approximately 48% of our natural gas production comes from shallow gas properties. Shallow gas is natural gas produced from thin, shallow sand formations predominantly located in southern areas of Alberta and Saskatchewan. These reservoirs typically cover a broad geographical area yielding sweet, low-pressure gas. In general, shallower gas targets are cheaper to drill and develop, but have relatively smaller reserves and lower productivity per well. During 2002, we drilled 130 shallow gas development wells. Our shallow gas properties provide consistent returns and production as they approach full development, and will continue to do so for years to come.

We are focused on gas exploration prospects in northeast British Columbia and the foothills of Alberta, and the testing of coal bed methane for future growth.

#### DEEP GAS EXPLORATION

Northeast British Columbia is attractive because it is expected to contain significant recoverable natural gas reserves. Winter-only access affects project cycle time, but the area offers relatively good access to infrastructure, an abundance of available acreage, and low drilling density. In 2002 and early 2003, we acquired an additional 9,000 net hectares of prospective lands. We drilled three exploration wells that were unsuccessful. During the year we also shot 200 km of 2D and 72 sq. km of 3D seismic and developed three deep prospects. The winter program is in progress with three deep Slave Point wells underway and a fourth planned for later in 2003 or early in 2004. Seismic programs will also be undertaken on our lands this year.

In a highly competitive market, we have assembled a good land base in northwest Alberta on trend with a number of foothills discoveries. In 2002, drilling success in the foothills resulted in three high deliverability gas wells, each capable of producing between 5 and 10 mmcf/d (gross). In 2003, we plan to drill two exploratory wells to test multiple targets.

#### COAL BED METHANE

Coal bed methane (CBM) is an untapped resource for gas production in Canada, but comprises 7% of the total gas supply in the United States. A given volume of coal can hold anywhere from 2 to more than 10 times the volume of gas found in a comparable conventional gas reservoir. Coal beds are usually saturated with water, and in most cases, water must be produced before any gas can be produced. De-watering the coal reduces pressure, allowing gas to “desorb” from the coal and be produced. As the gas begins to drive water out, permeability to gas increases, leading to increasing gas production rates. A typical CBM well shows increasing gas production rates for a period of generally one to three years before rates begin to decline.

Our CBM pilot project at Corbett is meeting expectations. We have increased our understanding and land holdings in this exciting new resource. At Corbett we strategically acquired an additional pilot project, increasing our total acreage position to over 190 sections gross, of which we hold a 40% to 50% working interest. We aligned ourselves with an experienced US CBM operator who has recently moved into Canada, accelerating our understanding and operating capabilities. Outside of Corbett, we have established a foothold in six new CBM areas, positioning ourselves to rapidly accelerate our activities once we are comfortable with the economic viability of the play.

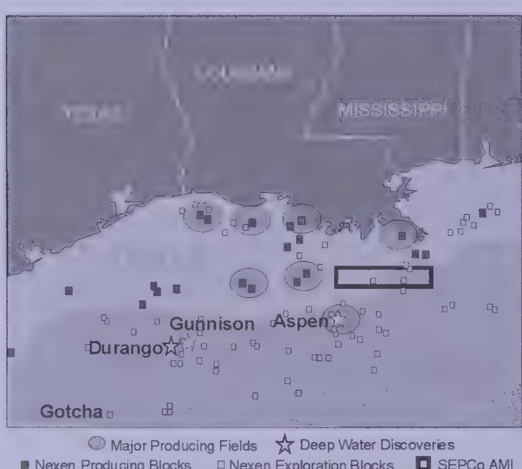
***Royalties and Taxes***

In Canada, the federal and provincial governments impose royalties on oil and gas production from lands where they own the mineral rights. Royalties vary depending on factors such as well production volumes, selling prices, recovery methods, drilling date of the well, and the date of initial production. Royalty rates can range from 16% to 25%. Crown royalties are not deductible for tax purposes as discussed below.

Some provinces also receive revenue by imposing taxes on production from lands where they do not own the mineral rights. In addition, the Province of Saskatchewan assesses a resource surcharge of 3.6% on gross Saskatchewan resource sales. This surcharge has been reduced to 2.0% on wells completed after October 1, 2002.

Profits earned in Canada from Canadian resource properties are subject to federal and provincial income taxes. Canadian entities are also subject to capital taxes. The federal capital tax rate is 0.225%. Provincial capital tax rates vary from 0.15% to 0.64%. The federal income tax rate is 29% for resource income allocated to Canadian provinces. Although crown royalties are not deductible for tax purposes, a 25% deemed "resource allowance" on net Canadian production income is deductible in computing taxes payable.

## United States




| **Acreage** (thousand acres) | Developed | Undeveloped | Total |
|---|---|---|---|
| Shallow-Water | | | |
| Gross | 175 | 162 | 337 |
| Net | 94 | 125 | 219 |
| Deep-Water | | | |
| Gross | 24 | 696 | 720 |
| Net | 9 | 286 | 295 |
| Total | | | |
| Gross | 199 | 858 | 1,057 |
| Net | 103 | 411 | 514 |

| **Proved Reserves** | Before Royalties | After Royalties |
|---|---|---|
| Crude Oil (mmbbls) | 64 | 58 |
| Natural Gas (bcf) | 326 | 279 |
| Total (mmboe) | 119 | 105 |

| **2002 Production** | Before Royalties | After Royalties |
|---|---|---|
| Crude Oil (mbbls/d) | 9.9 | 8.2 |
| Natural Gas (mmcf/d) | 112 | 93 |
| Total (mboe/d) | 28.6 | 23.7 |

Our oil and gas assets offshore in the US Gulf of Mexico are an important source of production and reserves growth for Nexen. We currently hold interests ranging from 3.7% to 100% in 190 federal lease blocks in the Gulf, 126 of which are located in water depths exceeding 660 feet.

Our strategy is to fully exploit our assets in the shallow waters of the Gulf while applying the expertise we have gained from over 20 years of operations in the Gulf to explore deep-water leases and accelerate development of our deep-water discoveries.

Royalties on our oil and gas production in the US average approximately 15% of working interest volumes. Deep-water production including Aspen, qualifies for royalty relief on the first 87.5 million equivalent barrels. Royalties on other Gulf and state water properties range from 15% to 25%. Profits from our US operations are subject to the US federal tax rate of 35%. State taxes in the jurisdictions in which we operate range from 0% to 8%.

***Shallow-water Exploration and Production***

Our shelf production comes from our shallow-water assets located offshore Louisiana and Texas, primarily from our interests in three fields: Eugene Island 257/258/259, Vermilion 76 (consisting of blocks 57, 65, 66 and 67) and West Cameron 148/170. We continue to exploit these assets, and to look for other opportunities on the shelf.

In late 2001, we acquired 100% working interests at Vermilion 76 and at Eugene Island 295. Since then we have drilled eight development wells at Vermilion 76, and more than doubled field production to approximately 40 million cubic feet per day.

In the second half of 2002, we experienced program delays and shut-in production due to hurricane activity. Hurricane Lili caused extensive damage to our production platform at Eugene Island 295, which has resulted in 100% of the production being shut-in since October but is expected to return to producing status during the first quarter of 2003.

In 2002, we signed an agreement with Shell Exploration and Production Company (SEPCo) to jointly explore a 1,044 square-mile area on the shelf. We have a 40% interest in this exploration area. The area of mutual interest (AMI) outlined in the agreement is targeting natural gas in deep Miocene Age reservoirs. This play is attractive as it has deep-water type reserve potential but is in close proximity to existing infrastructure on the shelf. We drilled one exploratory well in 2002 testing the deep Miocene Age reservoir but it resulted in a dry hole.

***Deep-water Exploration and Production***

Over the past decade, the deep-water Gulf of Mexico has moved from an exploration frontier to one of the most prospective sources of oil and gas production in the world. The deep-water Gulf is generally characterized by multiple productive horizons and high production rates, which greatly reduces risk and improves economics. The technology to find, drill, and develop deep-water discoveries is rapidly progressing and becoming more cost effective. In addition, the deep-water Gulf is in close proximity to infrastructure and continental US markets, allowing oil and gas discoveries to be quickly brought on stream. Large discoveries, high success rates, production infrastructure and attractive fiscal terms make this a premier exploration opportunity.

In 1997, we began building a deep-water acreage position, and are currently one of the largest independent leaseholders. In 2000 and 2001, we had discoveries at Aspen, Gunnison and Durango. Appraisal drilling justified proceeding with the commercial development of both the Aspen and Gunnison sub-basins.

ASPEN

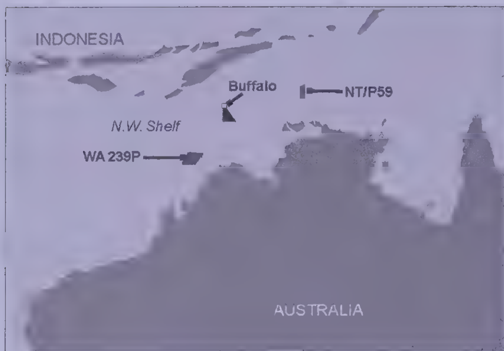
Aspen is located on Green Canyon Block 243 in 3,150 feet of water. In 2002, we increased our interest from 20% to 60% and proceeded with development. The project was developed using two subsea wells tied back to the Shell operated Bullwinkle platform 16 miles away. Both wells were tied in and production commenced in December 2002. In 2003, production is expected to average approximately 25,000 equivalent barrels per day (15,000 net). Production from Aspen is free of government royalties on the first 87.5 million equivalent barrels. Netbacks here are expected to be about twice our corporate average. We brought production on stream at Aspen just 19 months after the initial discovery.

GUNNISON AND DURANGO DISCOVERIES (GUNNISON SUB-BASIN)

Gunnison, our second deep-water project in the Gulf, is on schedule for production startup in early 2004. In 2001, our Board of Directors approved plans to develop our 30% interest in the Gunnison and Durango Fields. This area is located approximately 170 miles offshore Louisiana in water depths just over 3,100 feet, and includes Garden Banks Blocks 667, 668 and 669. Gunnison was discovered in May 2000 on Garden Banks Block 668 and Durango was discovered in June 2001 on Garden Banks Block 667. Gunnison is being developed using a truss SPAR platform with design capacity of 40,000 barrels of oil per day and 200 million cubic feet of gas per day. The initial development plans include 10 wells connected to the SPAR, all of which have been drilled. We plan to fill approximately 75% of the SPAR capacity with current development plans, leaving room for growth. Production at Gunnison also benefits from the first 87.5 million equivalent barrels being free of government royalties.

We are continuing to explore the deep-water Gulf. In 2003, we plan to drill at least five high-potential exploration wells, including deep-water tests in the Alaminos Canyon, Green Canyon and Garden Banks areas, plus a deep Miocene gas prospect on the shelf. Our Gotcha prospect in the Alaminos Canyon is of particular interest, as it is adjacent to the recently discovered Great White prospect. Additional wells could be drilled based on success and partner priorities.

## Australia




| **Acreage** (thousand acres) | Developed | Undeveloped | Total |
|---|---|---|---|
| Gross | 1 | 3,224 | 3,225 |
| Net | 1 | 3,224 | 3,225 |

| **Proved Reserves** (mmbbls) | Before Royalties | After Royalties |
|---|---|---|
| Buffalo Field | 4 | 3 |

| **2002 Production** (mbbls/d) | Before Royalties | After Royalties |
|---|---|---|
| Buffalo Field | 12.8 | 10.3 |

### *Buffalo*

The Buffalo field located offshore on the northwest shelf of Australia has been an excellent source of short-term production growth. This field produces high-quality crude oil that attracts a premium price. Production from Buffalo began in December 1999 using a fixed wellhead platform linked to a leased floating production storage and off-loading vessel (FPSO). In late 2000, we acquired the remaining 50% interest in this field and became the operator.

As a result of an extensive 3D seismic reprocessing program in 2001, we identified additional oil reserves that would not be recovered by the existing production wells. In 2002, we successfully completed a two-well infill drilling program which has allowed us to maximize our reserve recovery and has added incremental recoverable reserves.

In Australia, profits from offshore production, less allowable capital expenditures, are subject to Petroleum Resource Rent Tax (PRRT) at a rate of 40%. Any PRRT paid is deductible in computing corporate income tax. The corporate income tax rate in Australia is 30%.

### *Exploration Portfolio*

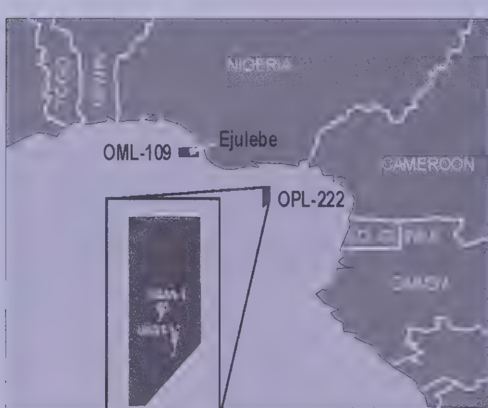
The experience, knowledge and infrastructure gained from our Buffalo operation supports our exploration program in other basins offshore Australia.

In 2002, we completed our interpretation of 3,700 km of 2D seismic which confirmed the existence of a prospect on NT/P59, a licence in the Money Shoals Basin. We have a 100% working interest in this block. We relinquished licences NT/P58 and NT/P60.

We have a 100% working interest in Block WA 239P in the Browse Basin, which spans 1.2 million acres. In 2002, we continued interpretation of our 2D seismic program and we have identified an exploration prospect.

We intend to find partners in 2003 to participate in further evaluation of these prospects before committing to the next phase of the work program.

## Nigeria




| **Acreage** (thousand acres) | Developed | Undeveloped | Total |
|---|---|---|---|
| Gross | 1 | 483 | 484 |
| Net | 1 | 108 | 109 |

| **Proved Reserves** (mmbbls) | Before Royalties | After Royalties |
|---|---|---|
| Ejulebe Field | 1 | 1 |

| **2002 Production** (mbbls/d) | Before Royalties | After Royalties |
|---|---|---|
| Ejulebe Field | 7.5 | 3.9 |

*Block OML-109 - Ejulebe*

We operate the Ejulebe field located in 45 feet of water on Block OML-109 in the Niger Delta, approximately 15 km offshore Nigeria. Crude oil production from Ejulebe is transported through a pipeline to a third-party owned FPSO where it is made available for export. We operate the block under a risk service contract, which requires us to provide exploration, development and operatorship services and fund all costs in return for a service fee payable out of production from the block.

*Block OPL-222*

In 1998, we acquired a 20% interest in Block OPL-222, which includes 469,000 acres and is located approximately 50 miles offshore in water depths ranging from 600 to 3,500 feet. In late 1998, the Ukot-1 exploration well, located in approximately 2,600 feet of water, encountered three oil-bearing intervals and flowed at a total rate of 13,900 barrels per day from two intervals. After an extensive 3D seismic program, Usan-1 was drilled in 2002 as a follow-up to our Ukot discovery. Usan was drilled to 9,000 feet in 2,500 feet of water and contained several oil-bearing reservoirs. One zone was production tested and flowed at a restricted rate of 5,000 barrels of oil per day. A multi-well program to appraise and delineate our discoveries is in progress and is expected to continue through the first half of 2003.

## Colombia


| **Acreage** (thousand acres) | Developed | Undeveloped | Total |
|---|---|---|---|
| Gross | 1 | 727 | 728 |
| Net | 1 | 548 | 549 |

| **Proved Reserves** (mmbbls) | Before Royalties | After Royalties |
|---|---|---|
| Guando | 6 | 6 |

| **2002 Production** (mbbls/d) | Before Royalties | After Royalties |
|---|---|---|
| Guando | 1.4 | 1.3 |

*Boqueron Block – Guando Discovery*

In 2000, we made our first discovery at Guando on the non-operated Boqueron Block. Boqueron is located in the Upper Magdalena Basin of central Colombia, approximately 45 km southwest of Bogota. Based on successful results from four appraisal wells and three development wells, we submitted an application for commerciality early in 2002. Our application was accepted by Ecopetrol, the national oil company. Ecopetrol exercised their right to back into a 50% interest in the development, reducing our interest from 40% to 20%. Under the arrangement, our share of costs incurred on Ecopetrol's behalf before they exercised their back-in right, are recoverable from future production.

Development drilling has been ongoing and a pilot program began in 2002 to test waterflood opportunities. We expect water injection to begin early in 2003 with results available as early as mid-year. Production from Guando is subject to a 5% to 25% royalty depending on daily production levels. The income tax rate in Colombia is 35%.

*Exploration Blocks*

In addition to Boqueron, we have interests in three exploration blocks in the Upper Magdalena Basin, which together span 0.7 million gross acres. Villarrica, Fusagasuga (Fusa) and El Descanso were acquired in 2000, Muisca in 2001 and Andino in 2002. Fusa has been relinquished and El Descanso will be relinquished in 2003. The table below describes activities that occurred in 2002:

| Block | Interest (%) | 2002 Activity |
|---|---|---|
| Boqueron Exploration | 40 | Negotiated new terms for deeper pool exploration efforts |
| Villarrica | 50 | Conducted 2D seismic program |
| Fusa | 50 | Drilled Atadero-1 exploration well and relinquished the Block |
| El Descanso | 50 | Evaluated Orion-1 exploration well |
| Andino | 100 | Signed the Block in 2002 |
| Muisca | 100 | Conducted surface geology program and relinquished a portion of the Block |

At Villarrica, evaluation of a recently acquired 2D seismic program is underway. We also plan to conduct 2D seismic programs on Muisca, Andino and possibly Boqueron subject to successful negotiations with Ecopetrol on new contractual terms. On all blocks except Boqueron, which is subject to a 50% back-in, Ecopetrol retains the right to back-in at the declaration of commerciality for a 30% interest. We have various exploration commitments on each block that normally include initial seismic reprocessing, followed by a 2D seismic program, and finally an exploration well. We have the right to exit each block at the end of the exploration phase.

### Brazil

In 2002, we acquired the right to earn a 20% interest in a 2,060 sq. km exploration license in Block BC-20 located in the Campos Basin, approximately 100 km offshore Brazil, by way of a farm-in arrangement. This provides us with a strategic entry into Brazil and enables us to build on our offshore knowledge in an under-explored basin. Block BC-20 offers several 2D seismically defined exploration prospects on trend with recent discoveries on adjacent blocks. The first well in a two-well drilling commitment was drilled in late 2002. We encountered no economic hydrocarbons. We plan to drill a second well on this block in the first half of 2003. If this second well is successful, we are committed to drill a third exploration well on the block.

## Synthetic Crude Oil

A key part of Nexen's strategy is the economic development of our bitumen resource to provide low risk, stable future growth.

We have a 7.23% joint venture interest in Syncrude Canada Ltd. (Syncrude). Syncrude mines shallow deposits of oil sands in Canada, extracts the bitumen and upgrades it to produce synthetic crude oil. We also have interests in numerous oil sands leases in the Athabasca region of northern Alberta and have acquired the rights to proprietary, patent-protected technology to upgrade bitumen recovered from these leases.

### Syncrude Joint Venture


| Acreage (thousand acres) | Developed | Undeveloped | Total |
|---|---|---|---|
| Gross | 106 | 152 | 258 |
| Net | 8 | 11 | 19 |

| Proved Reserves (mmbbls) | Before Royalties | After Royalties |
|---|---|---|
| | 264 | 226 |

| 2002 Production (mbbls/d) | Before Royalties | After Royalties |
|---|---|---|
| | 16.6 | 16.5 |

Our 7.23% interest was acquired in 1983. Syncrude was created in 1975 to mine shallow deposits of oil sands and extract and upgrade crude oil bitumen into a high-quality, light, synthetic crude oil. The oil sands are located on eight leases spanning 258,000 acres north of Fort McMurray, Alberta. Since startup in 1978, Syncrude has produced over 1.3 billion barrels of synthetic crude oil. The operating term for leases controlled by Syncrude currently extends to the year 2035. However, Syncrude can hold the leases for 80 years if there are plans to develop them. Syncrude mines oil sands at three mines: Base, North and Aurora. Approximately two tons of oil sands are required to produce one barrel of synthetic crude oil. The oil sands must be mixed with water to form a slurry. Air and certain chemicals are added to separate bitumen from the sand grains. The process at the Base Mine involves hot water, steam and caustic soda to create a slurry, while at the North Mine and the Aurora Mine the oilsands are mixed with warm water to produce a slurry. The slurries are transported to extraction facilities where they are treated to remove water and solids. The bitumen product is fed into a vacuum distillation tower and two cokers for primary upgrading. The resulting products are then separated into naphtha, light gas oil and heavy gas oil streams. These streams are hydrotreated to remove sulphur and nitrogen impurities and are mixed together to form light, sweet synthetic crude oil. Sulphur and coke, which are by-products of the process, are stockpiled for possible future sale.

The quality of Syncrude's synthetic crude oil typically allows it to be sold at a premium to WTI, adjusted for transportation, quality and currency differences.

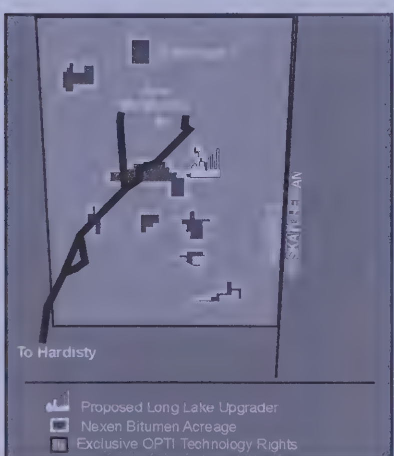
***Expansions***
In 1999, the Alberta Energy and Utilities Board (AEUB) approved an increase in Syncrude's production capacity to 465,700 barrels per day. At the end of 2001, Syncrude had increased its synthetic crude oil capacity to 246,500 barrels per day with the development of the Aurora Mine. In 2001, the Syncrude owners approved the third stage of the Syncrude expansion, which will increase capacity to 356,000 barrels per day (25,750 barrels net) by early 2005. Due to higher engineering, manufacturing, and construction costs, the estimated costs of the Stage 3 expansion have increased from initial estimates of $4.1 billion ($320 million net) to $5.7 billion ($412 million net).

***Royalties***
Syncrude pays a royalty to the Province of Alberta. Subsequent to 1987, this royalty was equal to 50% of Syncrude's deemed net profits after deduction of certain capital expenditures. In 1995, the Province announced generic royalty terms for new oil sands projects that provide for a royalty rate of 25% on net revenues after all costs have been recovered, subject to a minimum 1% gross royalty. In 1997, the Province of Alberta and the Syncrude owners agreed to move to the generic royalty terms when the total of all allowed capital costs incurred after December 31, 1995 equaled $2.8 billion (gross). That total was surpassed at the end of 2001, and so Syncrude moved to generic terms in January 2002.

During the transition period, the Province of Alberta's share of deemed net profits was based on a weighted average blended rate comprising a 50% net profits interest on base production of 74 million barrels per year, and a 25% net profits interest on annual production over 74 million barrels. In addition, 43% of allowed capital costs were applied as a deduction from the Province of Alberta's share of the deemed net profits.

| | **2002** | **2001** | **2000** |
|---|---|---|---|
| Effective annual Syncrude royalty rates on gross production | 1% | 4% | 17% |

## Premium Synthetic Crude Oil Project at Long Lake, Alberta




We have interests in numerous oil sands leases in the Athabasca region of northern Alberta – one of the largest non-conventional oil deposits in the world. These bitumen resources can be produced using Steam Assisted Gravity Drainage (SAGD), a technology now being commercialized at several locations in the region. SAGD involves the drilling of two parallel horizontal wells, generally between 2,300 and 3,300 feet in length with about 16 feet of vertical separation. Steam is injected into the shallower well, where it heats the bitumen that then flows by gravity to the deeper producing well. Recovery factors of 50% to 70% of the oil-in-place are possible with this technology. We have interests in SAGD projects at various stages of development including a 50% interest in a joint venture with OPTI Canada Inc. (OPTI).

*OPTI Joint Venture*
In 2001, we formed a joint venture with OPTI to develop in-situ bitumen using SAGD technology, and to construct a field upgrading facility on the Long Lake property, incorporating OPTI's patented OrCrude™ technology. As part of the agreement, Nexen acquired the exclusive right with OPTI to use the technology within a radius of approximately 100 miles of the Long Lake property, and the right to use the technology elsewhere in the world.

The OrCrude™ technology converts bitumen into partially upgraded sour crude oil and liquid asphaltenes. A 500-barrel per day demonstration plant applying this technology has been successfully upgrading bitumen from the Cold Lake and Athabasca regions since April 2001. By coupling the OrCrude™ process with commercially available hydrocracking and gasification technologies, the sour crude will be upgraded to light (37° to 43° API) premium synthetic crude oil and the asphaltenes will be converted to a low-energy, synthetic fuel gas containing free hydrogen (for use in the upgrading process). We estimate the capital costs of producing and upgrading bitumen based upon this technology will be comparable to those of surface mining and upgrading on a barrel of daily production basis. In addition, the project will have significantly lower price risk on input costs, since it manufactures its hydrogen and fuel gas from internally produced asphaltenes rather than purchased natural gas.

An application to construct a 70,000 barrel per day SAGD project and an integrated 70,000 barrel per day input (60,000 barrel per day premium synthetic crude output) upgrader at Long Lake (Lease 27) was submitted to the Province of Alberta and regulatory approval is anticipated in 2003. In order to optimize well design, a three-well pair SAGD pilot project at Long Lake is currently under construction and we expect bitumen production to begin in June 2003. Commercial production of bitumen is expected in the second half of 2006 before the upgrader is constructed. Upon successful completion of engineering studies now being carried out and the receipt of required approvals, engineering and construction of the commercial project will commence, with a target completion date in 2007. We are the operator of the Long Lake lease and will be responsible for construction, development and operation of the SAGD projects. OPTI will be responsible for design, construction and operation of the upgrader.

The royalty terms are consistent with the generic royalty terms for oil sands projects that provide for a royalty rate of 25% on net revenues after all costs have been recovered, subject to a minimum 1% gross royalty.

## Reserves, Production and Related Information

In addition to the tables below, we refer you to the Supplementary Financial Information in this Form 10-K for information on our oil and gas producing activities. Nexen has not filed with nor included in reports to any other United States federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

### Net Sales by Product

| (Cdn$ millions) | 2002 | 2001 | 2000 |
|---|---|---|---|
| Conventional Crude Oil and Natural Gas Liquids | 1,637 | 1,421 | 1,652 |
| Synthetic Crude Oil | 245 | 225 | 199 |
| Natural Gas | 347 | 497 | 425 |
| | 2,229 | 2,143 | 2,276 |

Crude oil and natural gas liquids represent approximately 84% of oil and gas sales, while natural gas represents the remaining 16%.

### Sales Prices and Production Costs

(Based on working interest production after royalties)

| | Average Sales Price [1] | | | Average Production Costs [1] | | |
|---|---|---|---|---|---|---|
| | 2002 | 2001 | 2000 | 2002 | 2001 | 2000 |
| Crude Oil and NGLs ($/bbl) | | | | | | |
| Yemen | 38.80 | 35.05 | 40.53 | 4.13 | 3.47 | 3.03 |
| Canada | 30.84 | 24.86 | 33.49 | 8.98 | 7.90 | 7.17 |
| United States | 38.87 | 38.35 | 44.18 | 10.95 | 7.24 | 6.04 |
| Australia | 40.30 | 38.71 | 41.05 | 12.14 | 14.38 | 6.92 |
| Other Countries | 38.96 | 37.35 | 40.13 | 10.69 | 9.94 | 9.69 |
| Synthetic Crude Oil | 40.89 | 39.90 | 44.84 | 19.26 | 20.29 | 22.20 |
| Natural Gas ($/mcf) | | | | | | |
| Canada | 3.57 | 5.02 | 4.38 | 0.70 | 0.54 | 0.62 |
| United States | 5.29 | 6.66 | 6.90 | 1.83 | 1.21 | 1.01 |

Note:
[1] Prices and unit production costs are calculated using our working interest production after royalties.

## Producing Oil and Gas Wells

(number of wells)

| | 2002 | | | | | |
|---|---|---|---|---|---|---|
| | Oil | | Gas | | Total | |
| | Gross [1] | Net [2] | Gross [1] | Net [2] | Gross [1] | Net [2] |
| Yemen | 259 | 135 | - | - | 259 | 135 |
| Canada | 3,886 | 2,402 | 2,364 | 2,081 | 6,250 | 4,483 |
| United States | 192 | 87 | 245 | 123 | 437 | 210 |
| Colombia | 19 | 4 | - | - | 19 | 4 |
| Australia | 4 | 4 | - | - | 4 | 4 |
| Nigeria | 3 | 3 | - | - | 3 | 3 |
| Total | 4,363 | 2,635 | 2,609 | 2,204 | 6,972 | 4,839 |

Notes:
[1] Gross wells are the total number of wells in which an interest is owned.
[2] Net wells are the sum of fractional interests owned in gross wells.

## Oil and Gas Acreage

(thousands of acres)

| | 2002 | | | | | |
|---|---|---|---|---|---|---|
| | Developed | | Undeveloped [1] | | Total | |
| | Gross | Net | Gross | Net | Gross | Net |
| Yemen [2] | 38 | 20 | 20,150 | 10,365 | 20,188 | 10,385 |
| Canada | 968 | 768 | 2,870 | 1,744 | 3,838 | 2,512 |
| United States | 199 | 103 | 858 | 411 | 1,057 | 514 |
| Australia | 1 | 1 | 3,224 | 3,224 | 3,225 | 3,225 |
| Nigeria [2, 3] | 1 | 1 | 483 | 108 | 484 | 109 |
| Colombia [4] | 1 | 1 | 727 | 548 | 728 | 549 |
| Brazil | - | - | 509 | 102 | 509 | 102 |
| Conventional Total | 1,208 | 894 | 28,821 | 16,502 | 30,029 | 17,396 |
| Synthetic Crude Total | 106 | 8 | 152 | 11 | 258 | 19 |

Notes:
[1] Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.
[2] The acreage is covered by production sharing contracts.
[3] The acreage is covered by a risk service contract.
[4] The acreage is covered by an association contract.

## Drilling Activity

(number of net wells)

| | 2002 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Net Exploratory | | | Net Development | | | |
| | Productive | Dry Holes | Total | Productive | Dry Holes | Total | Total |
| Yemen | - | 0.6 | 0.6 | 38.0 | 1.0 | 39.0 | 39.6 |
| Canada | 16.0 | 4.0 | 20.0 | 225.0 | 8.0 | 233.0 | 253.0 |
| United States | - | 1.4 | 1.4 | 14.9 | 0.6 | 15.5 | 16.9 |
| Australia | - | - | - | 2.0 | - | 2.0 | 2.0 |
| Other Countries [1] | 0.2 | 0.7 | 0.9 | 2.0 | 0.2 | 2.2 | 3.1 |
| Total | 16.2 | 6.7 | 22.9 | 281.9 | 9.8 | 291.7 | 314.6 |

| | 2001 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Net Exploratory | | | Net Development | | | |
| | Productive | Dry Holes | Total | Productive | Dry Holes | Total | Total |
| Yemen | - | 1.5 | 1.5 | 30.7 | 1.6 | 32.3 | 33.8 |
| Canada | 38.6 | 20.8 | 59.4 | 369.9 | 8.3 | 378.2 | 437.6 |
| United States | 3.8 | 1.2 | 5.0 | 5.3 | - | 5.3 | 10.3 |
| Australia | - | 0.4 | 0.4 | - | - | - | 0.4 |
| Other Countries [1] | 1.2 | 2.9 | 4.1 | 1.8 | 0.4 | 2.2 | 6.3 |
| Total | 43.6 | 26.8 | 70.4 | 407.7 | 10.3 | 418.0 | 488.4 |

**Drilling Activity (continued)**

| | 2000 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Net Exploratory | | | Net Development | | | |
| | Productive | Dry Holes | Total | Productive | Dry Holes | Total | Total |
| Yemen | - | - | - | 13.5 | 2.1 | 15.6 | 15.6 |
| Canada | 39.5 | 20.2 | 59.7 | 379.4 | 16.5 | 395.9 | 455.6 |
| United States | 1.9 | 2.5 | 4.4 | 8.1 | 1.5 | 9.6 | 14.0 |
| Australia | - | 0.9 | 0.9 | - | - | - | 0.9 |
| Other Countries [1] | 1.2 | 1.8 | 3.0 | - | - | - | 3.0 |
| Total | 42.6 | 25.4 | 68.0 | 401.0 | 20.1 | 421.1 | 489.1 |

Note:
[1] Other countries include drilling primarily in Nigeria, Colombia and Brazil.

At December 31, 2002, we were in the process of drilling 1 well (0.3 net) in the United States, 8 wells (4.2 net) in Canada, 4 wells (2.1 net) in Yemen, 1 well (0.2 net) in Nigeria, and 1 well (0.2 net) in Colombia.

## Oil and Gas Marketing

Our marketing operation sells our own crude oil and natural gas production, markets third-party crude oil and natural gas and engages in energy trading through the use of both physical and financial contracts (energy trading activities). These activities are intended to enhance price realizations from selling both proprietary and third-party oil and gas production, provide market and business intelligence in support of our oil and gas growth activities, and contribute independent earnings and cashflow.

We focus on four key areas: domestic oil marketing and trading, domestic gas marketing and trading, international oil marketing and trading, and producer services and transportation. Each area is involved in the purchase, transport, storage and sale of oil or natural gas from the point of production to end-use customers. We also trade on active markets such as the New York Mercantile Exchange and the International Petroleum Exchange as part of our total portfolio. We have offices in Calgary, Houston, Denver, Detroit, and Singapore to service our key market areas.

Our marketing operation also owns transportation assets and has investments in third-party controlled gas-processing facilities. Transportation assets include pipelines and batteries in the Lloydminster area as well as the Hay pipeline. In addition, we manage various natural gas transportation commitments on behalf of our Canadian oil and gas business segment and third-party clients. These management arrangements help optimize our energy trading activities. Our marketing operations are more fully described in Item 7.

## Chemicals Operations

Over the past three years, we have made significant investments to grow our capacity, expand internationally and lower our overall cost structure. These investments have allowed us to maintain a strong position in the bleaching chemicals industry. We manufacture, market and distribute sodium chlorate and chlor-alkali products (chlorine, caustic soda and muriatic acid) in Canada, the United States and Brazil. We also market a small amount of sodium chlorate and caustic soda in Asia.

| Average Annual Production Capacity | 2002 | 2001 | 2000 |
|---|---|---|---|
| Sodium Chlorate (short-tons) | | | |
| North America | 500,650 | 474,250 | 461,470 |
| Brazil | 57,320 | 42,550 | 39,000 |
| Total | 557,970 | 516,800 | 500,470 |
| Chlor-alkali (short-tons) | | | |
| North America | 351,844 | 351,844 | 351,844 |
| Brazil | 97,462 | 90,078 | 75,055 |
| Total | 449,306 | 441,922 | 426,899 |

The key factors driving the bleaching chemicals market are reliability of supply and technical service, and price. Our manufacturing facilities are modern and reliable, and strategically located to capitalize on competitive power costs and transportation infrastructure in order to minimize production and delivery costs. Electricity is the single largest cost incurred by our operations, representing over half of our cash costs. Other primary raw materials used in the production of sodium chlorate and chlor-alkali products are salt and fresh water. We secure long-term contracts for these materials to ensure sufficient supply and competitive costs. Labour is also a significant component of the manufacturing costs, with approximately 50% of our chemicals' workforce being unionized. We have active collective agreements in place at all of our unionized plants.

## North America


We manufacture sodium chlorate at six facilities in North America: Nanaimo, British Columbia; Bruderheim, Alberta; Brandon, Manitoba; Amherstburg, Ontario; Beauharnois, Quebec; and Taft, Louisiana. We also manufacture chlor-alkali products at North Vancouver, British Columbia.

In 1995, we combined our industrial chemicals operations in North America with Occidental's sodium chlorate facility located at Taft, Louisiana. We held an 85% interest in the venture and acted as managing partner. During 2000, we exchanged our oil and gas operations in Ecuador for Occidental's 15% interest in our chemicals operations. We now own 100% of our chemicals operations.

The pulp and paper industry consumes approximately 95% of sodium chlorate production in North America. Our North American sodium chlorate production is marketed to numerous pulp and paper mills under multi-year contracts that contain price and volume provisions. Approximately 25% of this production is sold in Canada and the remainder is sold in the US, with a small component marketed offshore. In 2002, we completed an expansion of our Brandon plant in Manitoba.

Our chlor-alkali facility in British Columbia manufactures caustic soda, chlorine and muriatic acid. In British Columbia, almost all of our caustic soda is consumed by local pulp and paper mills, while our chlorine is sold to various customers in the polyvinyl chloride, water purification and petrochemicals industries, primarily in the United States.

## Brazil


In December 1999, we acquired a 39,000 short-ton per year sodium chlorate plant and a 35,000 short-ton per year chlor-alkali plant in Brazil from Aracruz Cellulose S.A., the leading manufacturer of pulp in Brazil. Substantially all of our production is sold to Aracruz under a long-term sales agreement that has an initial six year take-or-pay component. In 2002, we completed an expansion of both the chlorate and chlor-alkali facilities to meet Aracruz's expansion needs.

# Other Activities

## Moose Jaw Asphalt

Nexen owned Moose Jaw Asphalt Inc., which produced asphaltic paving products, petroleum-derived fuels and specialty distillates. Effective January 2, 2002, we sold Moose Jaw Asphalt. The financial results of this operation for 2001 and 2000 are included in Corporate and Other Items in note 15 to the Consolidated Financial Statements.

## Power Generation Facility

In 2000, we committed to enter into a lease agreement upon the completion of construction of a 106 Megawatt (MW) high-efficiency power start up generation facility. The facility was constructed at our operated Balzac gas plant located near Calgary, Alberta and began operations during the fourth quarter of 2001. In 2002, we refinanced the lease and purchased the facility for $67 million, which was the cost of construction plus interest on advances during the construction phase. We included this amount in capital expenditures for the year ended December 31, 2002. The average load for 2002 was 17.8 MW which is expected to increase in 2003. The financial results of the power generation facility are included in Corporate and Other Items in note 15 to the Consolidated Financial Statements.

## ADDITIONAL FACTORS AFFECTING BUSINESS

See Item 7 of this Form 10-K.

## Government Regulations

Our operations are subject to various levels of government controls and regulations in the countries in which we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, all of which are subject to change from time to time. Current legislation is generally a matter of public record, and we are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. However, we do participate in many industry and professional associations and otherwise monitor the progress of proposed legislation and regulatory amendments.

## Environmental Regulations

### Oil and Gas Operations

Our oil and gas operations are subject to government laws and regulations designed to protect the environment in the countries where we operate. We believe that our operations comply in all material respects with applicable environmental laws.

#### *Canada*

In Canada, these provisions, which are implemented principally by Environment Canada, Transport Canada and comparable provincial agencies, govern the management of hazardous waste, the discharge of pollutants, the construction of new discharge sources and the transportation of dangerous goods. The laws generally provide for civil and criminal penalties and fines, as well as injunctive and remedial relief.

#### *United States*

In the United States, these provisions, which are implemented principally by the United States Environmental Protection Agency, the Department of Transportation, the Department of the Interior and comparable state agencies, govern the management of hazardous waste, the discharge of pollutants into the air and into surface and underground waters, the construction of new discharge sources, the manufacture, sale and disposal of chemical substances, and surface and underground mining. These laws generally provide for civil and criminal penalties and fines, as well as injunctive and remedial relief.

#### *Yemen*

In Yemen, the Yemen Environmental Protection Law was ratified by Parliament and issued by Presidential decree in October 1995. Yemen Republican Decree No. 11 in respect of Protection of the Maritime Environment from Pollution was passed in 1993 and establishes the Public Corporation for Maritime Affairs as the regulatory authority for maritime activities. Under the terms of an agreement with the Government of Yemen in March 1996, we prepaid the dismantlement and site restoration costs on the Masila Block Development Project, and were released from any further obligation relating to these costs on this block.

#### *Nigeria*

In Nigeria, we have a risk service contract on Block OML-109 with an indigenous company. The indigenous company is responsible for obtaining all regulatory approvals associated with development in Nigeria. Pollution control regulations in oil and gas operations are governed by the Principal Legislation of Petroleum Act 1969. The regulations are made pursuant to section 8(i)b(iii) of the Petroleum Act. Revisions to existing regulations regarding waste discharges, environmental management systems, audits, decommissioning and oil spillage investigation were to have been issued before the end of 1999 but have been delayed. In November 1999, the Federal Ministry of the Environment announced that, pursuant to the Environmental Impact Assessment (EIA) Decree No. 86 of 1992, they have been charged with full responsibility for supervising all aspects of the environmental management of the oil and gas industry, replacing the environment division of the Department of Petroleum Resources and the defunct Federal Environmental Protection Agency. The timing and implications of these changes have yet to be determined.

*Australia*
In Australia, the offshore petroleum industry is regulated by broadly consistent Commonwealth, State and Territory legislation. The States and Northern Territory have jurisdiction over onshore petroleum operations, including petroleum within coastal waters. Petroleum operations beyond three nautical miles from the territorial sea baseline are subject to the Commonwealth Petroleum (Submerged Lands) Act 1967 (PSLA). The key subordinate and related legislation which impact offshore health and safety are the Petroleum (Submerged Lands) (Management of Safety on Offshore facilities) Regulations 1996 and the State and Northern Territory OH&S Acts and Regulations, which are applied through Section 9 of the PSLA. Other State and Territory laws are applied to offshore areas through Section 11 of the PSLA. There are generally two administrative decision-making bodies in respect of each offshore area; a Joint Authority, comprising the Commonwealth Minister responsible for resources and the equivalent State or Northern Territory Minister, which is the principle decision-making body, and a Designated Authority, which handles the day-to-day administrative matters relating to petroleum activities in the defined area. Titleholders under the PSLA are responsible for all petroleum related activities (including safety) in the permit/licence area. The designated representative of the titleholder is the operator. In July of 2000, the Environmental Protection and Biodiversity Conservation Act became law. Under this Commonwealth Act, operators are required to assess their projects to determine whether an action is likely to have a significant impact on matters of national environmental significance, and make a decision respecting submission of that assessment to a public referral process. The referral is expected to add some time to the existing approval process but have little impact on most routine activities and operations.

*Colombia*
In Colombia, operations are subject to environmental regulations under the Ministry of the Environment. Community consultation is regulated by the Ministry of the Interior. The basic process, which results in an average time to receipt of license of between one and three years, starts with the Ministry of Interior requirements for community consultation, followed by preparation of the required environmental impact assessment and management plans, followed by review within the Ministry of the Environment and the regional environmental authorities. Recent attempts to streamline issuance of hydrocarbon licenses have been renewed under the new Uribe government.

From time to time, we may conduct activities in countries where environmental regulatory frameworks are in various stages of evolution. Where regulations are lacking, we observe Canadian standards where applicable, as well as internationally accepted industry environmental management practices.

*Kyoto Protocol*
For a discussion of the Kyoto Protocol, see the Business Risk Management section in Item 7.

## Syncrude Operations
Syncrude is regulated by the AEUB and the Alberta Department of Environment (AENV). In 1999, the AEUB extended Syncrude's operating term through 2035 giving the flexibility required for ongoing orderly development of the operation and reclamation of the site. The AENV issued its approval under the Alberta Environmental Protection and Enhancement Act effective December 21, 1995. The approval is for the 10-year period through to December 2005, which is the maximum term provided for in the legislation, and is a consolidated document covering air, land, water and waste management matters. Land reclamation is proceeding at a rate of approximately 200 hectares per year, thereby minimizing annual future reclamation costs.

## Chemicals Operations
We maintain an active environmental and safety program at our chemicals sites to further our goal of excelling as a Responsible Care® Organization. Many of our chemicals facilities (i.e. Amherstburg, Beauharnois, Brandon, Bruderheim, Nanaimo, and North Vancouver) have completed quantitative risk assessments to assist both the facilities and the communities in their emergency response and risk management plans. The results of these reviews have been communicated to each respective community.

Since 1972, our North Vancouver facility has been the British Columbia regional control center for the North America Chlorine Emergency Plan. Through this plan, we participate with other chlorine producers to provide professional and responsive action in the event of a chlor-alkali related emergency anywhere in their region of responsibility.

We have taken an active role in the Canadian Chemical Producers' Association (CCPA), CAER (Community Awareness and Emergency Response) and TRANSCAER (Transportation CAER) projects. In 1989, we and other members of the CCPA expanded the CAER and TRANSCAER programs to the Responsible Care® initiative. This initiative is based on the industry's commitment to the responsible development, manufacture, transportation, handling, distribution, use and ultimate disposal of chemicals so as to minimize adverse effects on people and the environment. We successfully completed the

CCPA's Round 1 Responsible Care® verification process in 1995. In 1998, we were the first company to undergo Round 2 verification of our Responsible Care® management systems. In 2000, our Taft facility successfully completed a third-party American Chemistry Council Responsible Care® Management System Verification to ensure compliance to the Responsible Care® codes of practice in the United States. In 2002, we completed a CCPA Round 3 Responsible Care® reverification.

Regulations that apply to our pulp and paper customers are significant to our chemicals operations. In January 1992, the Province of British Columbia amended the *Pulp Mill and Pulp and Paper Mill Liquid Effluent Control Regulation* to require all British Columbia pulp mills to achieve a zero AOX (Absorbable Organic Halogens) effluent discharge standard from their bleaching processes by the end of 2002. In June 2002, the Province of British Columbia announced that it would amend the Regulation to require all British Columbia pulp mills to meet a new effluent discharge standard of 0.5 kilogram/Air Dried tonne AOX annual average. Currently, all British Columbia pulp mills are complying with the new standard.

Operations in the United States are also subject to various federal and state laws and regulations which govern the management of hazardous waste, the discharge of pollutants into the air and into surface and underground waters, the construction of new discharge sources, and the manufacture, sale and disposal of chemical substances.

The Aracruz facility in Brazil operates in accordance with a number of federal and state laws and regulations, as well as a new civic environmental policy for the city of Aracruz. These regulations address various aspects of environmental management, including environmental zoning for industrial applications, assessment of environmental impacts and licensing of activities that may impact the environment.

Our Brazil chemicals operation is a member of the Brazilian Industrial Chemical Association (ABIQUIM) and is committed to the ABIQUIM Responsible Care initiative. We are currently implementing management systems in Brazil to fulfill the Responsible Care Codes of Practice, with implementation scheduled for completion in 2003.

### Other Activities

Our Balzac gas plant and power generation facility received Round 1 Responsible Care® verification in 2002.

### Environmental Provisions and Expenditures

At December 31, 2002, $205 million has been provided in the accounts for future dismantlement and site restoration costs, which are currently estimated at approximately $544 million for all of our oil and gas and chemicals facilities. During 2002, we recorded a provision for future dismantlement and site restoration costs of $43 million.

During 2002, our capital expenditures for environmental-related matters, including environment control facilities, were approximately $20 million. Our operating expenditures for environmental-related matters were approximately $6 million. Environmental related capital expenditures in 2003 are expected to be similar to 2002.

## EMPLOYEES

At December 31, 2002, we had 2,767 employees in the following operations - Oil and Gas: Canada 575, United States 165, International 1,028 (Yemen 817, Canada and other areas 211); Chemicals 459; Oil and Gas Marketing 105, Corporate 336 and Technical Services 99. These totals include 744 national employees in the following countries – Colombia 25, Australia 16, Nigeria 25, Brazil 52, and Yemen 626.

Approximately 50% of the employees of our Chemicals operations are unionized. The unionized facilities are located at North Vancouver, Squamish, and Nanaimo, British Columbia; Brandon, Manitoba; Beauharnois, Quebec and Aracruz, Brazil. Union contracts at Nanaimo and Beauharnois are in effect until 2003 and until 2004 for Squamish, Brandon, and North Vancouver. Union contracts in Brazil are renewed on an annual basis.

Approximately 10% of the employees of our Canadian oil and gas operations are unionized. Unionized facilities are located at Balzac, Alberta, with a contract in effect until 2004.

Information on our executive officers is presented in Item 10 of this report.

## Item 3. Legal Proceedings

There are a number of lawsuits and claims pending against Nexen, the ultimate results of which cannot be ascertained at this time. Management is of the opinion that any amounts assessed against us would not have a material adverse effect upon our consolidated financial position or results of operations.

Nexen received an order on February 17, 1999, under the British Columbia Waste Management Act to conduct a comprehensive remediation program, including soil and ground water remediation, with respect to our former chlor-alkali plant site at Squamish, British Columbia. The Order is within the scope of contemplated and accrued environmental remediation requirements for the former plant site and does not constitute a fine or penalty upon Nexen. We are in compliance with the Order.

Nexen's US operations have received, over the years, notices and demands from the United States Environmental Protection Agency, state environmental agencies, and certain third parties seeking to require investigation and remediation under federal or state environmental statutes. Although no assurances can be made, we believe our US operations are protected from any present or future material liabilities that may arise from these sites because of Assumption and Indemnification Agreements in place.

## Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of Nexen's Security holders during the fourth quarter of 2002.

## Item 5. Market for the Registrant's Common Shares and Related Stockholder Matters

Nexen's common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol NXY.

On December 31, 2002, there were 1,372 registered holders of common shares and 122,965,830 common shares outstanding. The number of registered holders of common shares is calculated excluding individual participants in securities positions listings.

**Trading Range of Nexen's Common Shares**

| ($/share) | Toronto Stock Exchange | | New York Stock Exchange | |
|---|---|---|---|---|
| | High | Low | High | Low |
| | (Cdn $) | | (US $) | |
| 2002 | | | | |
| First Quarter | 39.75 | 29.70 | 25.11 | 18.57 |
| Second Quarter | 42.50 | 37.20 | 28.04 | 23.30 |
| Third Quarter | 42.18 | 34.34 | 27.71 | 21.70 |
| Fourth Quarter | 37.78 | 31.00 | 23.85 | 19.79 |
| 2001 | | | | |
| First Quarter | 39.90 | 31.00 | 25.77 | 20.69 |
| Second Quarter | 40.65 | 32.40 | 26.61 | 20.60 |
| Third Quarter | 41.50 | 28.10 | 26.12 | 17.95 |
| Fourth Quarter | 35.21 | 29.51 | 22.39 | 18.73 |

| **Quarterly Dividends on Common Shares** ($/share) | First Quarter | Second Quarter | Third Quarter | Fourth Quarter |
|---|---|---|---|---|
| 2002 | 0.075 | 0.075 | 0.075 | 0.075 |
| 2001 | 0.075 | 0.075 | 0.075 | 0.075 |

Payment date for dividends was the first day of the next quarter.

The Income Tax Act of Canada requires us to deduct a withholding tax from all dividends remitted to non-residents. In accordance with the Canada-US Tax Treaty, we have deducted a withholding tax of 15% on dividends paid to residents of the United States, except in the case of a company that owns at least 10% of the voting stock where the withholding tax is 5%.

The Investment Canada Act requires that a "non-Canadian" (as defined) file notice with Investment Canada and obtain government approval prior to acquiring control of a "Canadian business" (as defined). Otherwise, there are no limitations, either under the laws of Canada or in Nexen's charter on the right of a non-Canadian to hold or vote Nexen's securities.

On February 3, 2000, at a Special Meeting of Shareholders, a Shareholder Rights Plan was approved. On May 2, 2002, at the Annual General and Special Meeting of Shareholders, an Amended and Restated Shareholder Rights Plan (Plan) was approved. The Plan creates a right, which attaches to each present and future outstanding common share. Each right entitles the holder to acquire additional common shares during the term of the right. Prior to the separation date, the rights are not separable from the common shares and no separate certificates are issued. The separation date would typically occur at the time of an unsolicited takeover bid, but our Board can defer the separation date.

The Plan creates a right, which can only be exercised when a person acquires 20% or more of our common shares (a Flip-In Event), for each shareholder, other than the 20% buyer, to acquire additional common shares at one-half of the market price at the time of exercise. The Plan must be reapproved by shareholders on or before our annual general meeting in 2005 to remain effective past that date.

On April 17, 2000, the shareholders approved the repurchase from Occidental and cancellation of 20 million common shares.

Under the terms of our stock option plan, the Board of Directors may grant stock options to directors, officers and employees. Nexen does not receive any consideration when options are granted.

Equity Compensation Plan Information:

| | Number of securities to be issued upon exercise of outstanding options | Weighted-average exercise price of outstanding options | Number of securities remaining available for future issuance under equity compensation plans |
|---|---|---|---|
| Equity compensation plans approved by shareholders | 9,475,985 | $30.00 | 9,759,545 |

## Item 6. Selected Financial Data

### Five Year Summary of Selected Financial Data in Accordance with US GAAP

| (Cdn$ millions) | **2002** | **2001** | **2000** | **1999** | **1998** |
|---|---|---|---|---|---|
| **Results of Operations** | | | | | |
| Net Sales [1] | 2,606 | 2,593 | 2,705 | 1,646 | 1,472 |
| Net Income (Loss) | 352 | 365 | 522 | 63 | (115) |
| Earnings (Loss) per Common Share ($/share) [2] | 2.88 | 3.03 | 4.17 | 0.46 | (0.84) |
| Production – Before Royalties (mboe/d) [3] | 269 | 268 | 256 | 239 | 266 |
| Production – After Royalties (mboe/d) [3] | 176 | 184 | 171 | 163 | 200 |
| **Financial Position** | | | | | |
| Total Assets [2] | 6,764 | 5,609 | 5,874 | 4,922 | 5,025 |
| Long-Term Debt | 2,575 | 2,242 | 2,238 | 1,997 | 1,777 |
| Shareholders' Equity | 1,812 | 1,414 | 1,050 | 1,130 | 1,074 |
| Capital Expenditures | 1,625 | 1,404 | 915 | 612 | 950 |
| Dividends per Common Share ($/share) | 0.30 | 0.30 | 0.30 | 0.30 | 0.30 |
| Common Shares Outstanding (thousands) [1] | 122,966 | 121,202 | 119,855 | 138,145 | 137,373 |

Notes:

1 Certain transportation costs previously shown net in sales have been reclassified to transportation and other. See note 1(r) to the Consolidated Financial Statements.

2 During 2000, we entered into an agreement to repurchase 20 million Nexen common shares, as described in note 8 to the Consolidated Financial Statements.

3 In 1999, production and total assets decreased as we sold our North Sea assets and certain producing assets in Canada. These North Sea assets were producing 34 mmcf/d of gas and the Canadian assets were producing 40 mboe/d. In 2000, production increased as additional development wells were brought on stream in Yemen and Buffalo in Australia began producing.

## Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

*The following should be read in conjunction with the Consolidated Financial Statements included in this report. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of the significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in note 16 to the Consolidated Financial Statements. Unless otherwise noted, tabular amounts are in millions of Canadian dollars, and sales volumes, production volumes and reserves are before royalties. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies. See the Oil and Gas Producing Activities section in the Supplementary Financial Information for our production and reserves after royalties.*

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## HIGHLIGHTS

| (Cdn$ millions) | **2002** | **2001** | **2000** |
|---|---|---|---|
| Net Income | 452 | 450 | 602 |
| Earnings per Common Share ($/share) | 3.34 | 3.40 | 4.52 |
| Cash Flow from Operations [1] | 1,383 | 1,423 | 1,569 |
| Oil & Gas Production (mboe/d) [2] | 269 | 268 | 256 |
| Capital Expenditures | 1,625 | 1,404 | 915 |
| Proved Reserve Additions, net of Dispositions (mmboe) [2] | 102 | 135 | 132 |
| Net Debt [3] | 1,775 | 1,460 | 1,344 |
| Net Debt to Cash Flow (times) [4] | 1.4 | 1.1 | 0.9 |

Notes:

1 We evaluate our performance and that of our business segments based on earnings and cash flow from operations. Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other. We consider it a key measure as it demonstrates our ability and the ability of our business segments to generate the cash flow necessary to fund future growth through capital investment and repay debt.

| (Cdn$ millions) | 2002 | 2001 | 2000 |
|---|---|---|---|
| Cash Flow from Operating Activities | 1,322 | 1,566 | 1,329 |
| Changes in Non-Cash Working Capital | 46 | (143) | 243 |
| Other | 15 | - | (3) |
| Cash Flow from Operations | 1,383 | 1,423 | 1,569 |

2 Production and reserves include our working interest before royalties. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.

3 Long-term debt less working capital.

4 Net debt divided by cash flow from operations after dividends on Preferred Securities.

## STRATEGY

To succeed in the exploration and production business we must continue to locate and develop economic oil and natural gas reserves. Our capital investments must add new reserves to replace and grow existing production, and also add value. We believe value-based growth is best delivered through full-cycle exploration and development activities.

We pursue a predominantly grassroots, exploration-led strategy, supplemented by targeted, strategic acquisitions and the development of innovative technology to competitively exploit our bitumen resource. This strategy is supported by:

- solid core assets that provide free cash flow to finance new development projects for near-term growth;
- an active exploration program aimed at longer-term growth; and
- a culture based on integrity and social responsibility.

Our fundamental goal is to grow shareholder value. We focus on per-share performance and regularly report on cash flow and earnings per share. We target to grow the physical deliverables to our shareholders that are independent of price volatility. We allocate capital to projects based first on their investment returns and strategic fit, and second on the potential to grow reserves and production. To maximize returns, we try to operate the majority of our core assets and control offsetting acreage and infrastructure for future development.

Our global growth strategy focuses on four major areas: the deep-water Gulf of Mexico, the Middle East, West Africa and the Athabasca region of western Canada. The basins in these areas offer an optimal combination of prospectivity, attractive commercial terms and low costs. In building our portfolio, we target material opportunities with an attractive risk/reward balance and multiple opportunities for organic growth, and those that build on our technical strengths. Our strengths include: operating offshore, extensive experience with oil sands, bitumen and heavy oil, operating in foreign jurisdictions such as the Middle East, managing low pressure reservoirs, constructing and operating large-scale facilities, operating in difficult and remote environments and our strong marketing capabilities.

With our exploration success over the last three years, our focus in 2002 shifted to developing these successes. This included Aspen and Gunnison in the deep-water Gulf of Mexico, Guando in Colombia, our Long Lake Synthetic Crude Project in the Athabasca region of Alberta and the Syncrude expansion. With the exception of Aspen, these projects have yet to contribute significantly to production and cash flow as they are still in the development stage. Annual proved reserve additions fluctuate due to timing of recognizing proved reserves, dispositions and revisions.

Our strategy for maximizing value in our marketing operations is to grow our business with lower-risk opportunities. For our chemicals business, our strategy is to remain a low-cost producer in North America, while capturing an increasing share of the growing markets in South America.

## 2002 CAPITAL INVESTMENT

We invested a record $1.6 billion in 2002, a 16% increase over 2001 levels:

- 41% was invested in core assets to maintain existing production levels;
- 43% was invested in our major development projects for near-term production growth; and
- 16% was invested in exploration for longer-term production growth.

| (Cdn$ millions) | Exploration | Development | Other | Total |
|---|---|---|---|---|
| Oil & Gas | | | | |
| Yemen | 22 | 209 | - | 231 |
| Canada | 60 | 262 | - | 322 |
| United States | 116 | 541 | - | 657 |
| Australia | 3 | 46 | - | 49 |
| Other | 58 | 23 | - | 81 |
| | 259 | 1,081 | - | 1,340 |
| Syncrude | - | 141 | - | 141 |
| Chemicals | - | - | 45 | 45 |
| Marketing, Corporate and Other [1] | - | - | 99 | 99 |
| Total Capital | 259 | 1,222 | 144 | 1,625 |

Note:
[1] Includes $67 million for our Balzac power generation facility.

In addition to maintaining production from our core assets (see Production section in this MD&A), our 2002 capital program delivered the following:

### United States Gulf of Mexico

***Aspen Onstream***

- Invested $311 million in 2002 to drill and complete two subsea development wells and tie back to Shell's Bullwinkle production platform.
- First well onstream in early December after a six-week construction delay due to hurricane activity; second well onstream late December 2002; both wells added minimal production in 2002 given late start-up.
- Production is currently ramping up to expected rates of approximately 15,000 boe/d (net to us).
- No significant capital investment required in 2003.

***Gunnison Development On-Track***

- Invested $111 million in 2002 to complete 55% of the SPAR production facility and drill six development wells with a seventh in progress at year-end.
- Development is on budget and on schedule for first production in early 2004.
- In 2003, we plan to invest $83 million to complete and tie-in the subsea wells to the SPAR production platform arriving from Finland this summer.

***Exploitation of 2001 Acquisitions***

- Invested $83 million in two offshore producing properties acquired late in 2001 — Vermilion 76 and Eugene Island 295.
- Drilled eight development wells and added compression at Vermilion 76 more than doubling daily gas production to 40 million cubic feet per day in late 2002.
- Drilled one new well and added compression at Eugene Island 295 before the field was extensively damaged by Hurricane Lili; field has been shut-in since October but is expected to return to producing status during the first quarter of 2003.

*Exploration for Deep Miocene Gas*

- Drilled first well, Fergana (40% interest), as part of our agreement with Shell Exploration & Production Company to jointly explore the continental Shelf for natural gas in Deep Miocene reservoirs.
- Well was abandoned and costs of $23 million were written off in the fourth quarter.
- We plan to drill at least two more wells in the joint venture area in 2003 and 2004.

## Canada

*Long Lake Pilot Project Commenced*

- Invested $80 million in 2002 to expand our recoverable resource potential to 4 billion barrels for the Long Lake and Meadow Creek properties, consulted with communities in support of our regulatory applications, continued detailed design and construction of the SAGD pilot project and carried out project design and cost estimation work.
- In 2003, we plan to invest $130 million to pilot-test SAGD technology at Long Lake and finalize a comprehensive cost assessment based upon detailed engineering design.
- Expect final regulatory approvals in fall 2003 and plan to decide on full-scale commercial project by year-end.

*Core Asset Optimization Continues*

- Began field testing enhanced extraction technologies in an effort to improve recoveries from some of our heavy oil properties.
- Built a strong land position targeting Coal Bed Methane (CBM) opportunities and commenced CBM pilot project.

## Syncrude

*Stage 3 Expansion Continues*

- Invested $141 million to fund our 7.23% share of Stage 3 expansion.
- Engineering and design is 90% complete for the Mildred Lake upgrader expansion (UE-1) and the second bitumen extraction train at the Aurora mine; construction is 12% complete for UE-1 and 50% complete for the Aurora train.
- In 2003, we plan to invest $150 million for the continued upgrader expansion and completion of the Aurora train.
- Stage 3 is expected to add 101,500 barrels (7,300 barrels net) of daily production in early 2005.

## Yemen

*Masila Exploitation Continues*

- Invested $402 million ($209 million net) to drill and equip 74 new development wells and expand facilities to maintain production at 226,900 barrels per day.

*Unsuccessful Well on Block 59*

- Drilled the Al Mawarid-1 exploration well on Block 59 without encountering commercial quantities of hydrocarbons.

## Australia

- Drilled two successful infill wells at Buffalo offshore Australia.

## Other Oil & Gas

*Guando Development Commences in Colombia*

- Drilled 12 primary-recovery development wells and commenced installation of waterflood pilot facilities to improve recoveries.
- Development drilling increased gross production to 7,300 barrels per day (2,200 net) by year-end.
- In 2003, we plan to invest $35 million to drill 24 wells, complete pipeline construction and evaluate the pilot waterflood performance.

*Exploration Success Offshore Nigeria*

- Invested $4 million and discovered oil at Usan on Block OPL-222 in the first quarter.
- Discovery well encountered several oil-bearing zones and tested at restricted rates in excess of 5,000 barrels per day.
- Currently appraising Usan and our 1998 discovery at Ukot on the same block.
- In 2003, we are continuing a program to appraise and delineate our discoveries.

*Unsuccessful Exploration Well Offshore Brazil*

- Drilled an exploration well on Block BC-20 in the Campos Basin which did not encounter commercial hydrocarbons and wrote off $5 million in the third quarter.
- In early 2003, we plan to drill a second exploration well on Block BC-20.

### Chemicals

- Expanded low-cost sodium chlorate capacity at Brandon by 60% or 70,000 tonnes per year to 195,000 tonnes per year.
- Expanded our sodium chlorate capacity in Brazil by 70% to 60,000 tonnes per year and chlor-alkali capacity by 30% to 91,160 tonnes.

### Other

- In 2002, we paid $67 million to refinance an operating lease related to the construction of a natural gas-fired power generation facility at our Balzac gas plant near Calgary.

## FINANCIAL RESULTS

### Year to Year Change in Net Income

| (Cdn$ millions) | 2002 vs 2001 | 2001 vs 2000 |
|---|---|---|
| **Net Income for 2001 and 2000** | 450 | 602 |
| Favourable (unfavourable) variances: | | |
| Cash Items: | | |
| Production volumes, net of royalties: | | |
| Crude oil | 28 | 123 |
| Natural gas | (18) | 30 |
| Commodity prices, net of royalties: | | |
| Crude oil | 190 | (308) |
| Natural gas | (114) | 22 |
| Oil and gas operating expense: | | |
| Conventional | (65) | (66) |
| Synthetic | (1) | (16) |
| Marketing | (23) | 48 |
| Chemicals | 1 | 3 |
| General and administrative | (16) | (19) |
| Interest expense | 3 | 20 |
| Current income taxes | (7) | 26 |
| Other | (18) | (9) |
| Total Cash Variance | (40) | (146) |
| Non-Cash Items: | | |
| Depreciation, depletion and amortization | | |
| Oil and Gas | (85) | 38 |
| Other | (10) | 4 |
| Exploration expense | 76 | (92) |
| Future income taxes | 82 | 77 |
| Other | (21) | (33) |
| Total Non-Cash Variance | 42 | (6) |
| **Net Income for 2002 and 2001** | 452 | 450 |

***2002 vs 2001 – Stable earnings year over year***

Net income remained strong due to narrow crude oil price differentials, stable production and reduced dry hole expense. Weaker natural gas prices, cost pressures and lower profits from Marketing offset the positive impact of crude oil prices.

***2001 vs 2000 – 25% decrease in net income***

Net income decreased largely as a result of a US $4.24 per barrel decrease in WTI. Record production levels, excellent results from Marketing and lower costs of financing helped mitigate the impact of crude oil price declines.

Significant variances in net income are explained further in the following sections.

## OIL AND GAS

### Production

| | 2002 | | 2001 | | 2000 | |
|---|---|---|---|---|---|---|
| | Before Royalties | After Royalties | Before Royalties | After Royalties | Before Royalties | After Royalties |
| Oil and Liquids (mbbls/d) | | | | | | |
| Yemen | 118.0 | 55.8 | 118.3 | 55.5 | 111.9 | 50.7 |
| Canada | 56.3 | 43.4 | 58.0 | 48.3 | 53.9 | 44.0 |
| United States | 9.9 | 8.2 | 10.0 | 8.3 | 11.1 | 9.3 |
| Australia | 12.8 | 10.3 | 10.2 | 9.6 | 12.0 | 12.0 |
| Other Countries | 8.9 | 5.2 | 6.2 | 5.3 | 6.4 | 5.4 |
| Syncrude | 16.6 | 16.5 | 16.1 | 15.5 | 14.7 | 12.1 |
| | 222.5 | 139.4 | 218.8 | 142.5 | 210.0 | 133.5 |
| Natural Gas (mmcf/d) | | | | | | |
| Canada | 167 | 128 | 174 | 147 | 161 | 135 |
| United States | 112 | 93 | 121 | 99 | 113 | 92 |
| | 279 | 221 | 295 | 246 | 274 | 227 |
| Total (mboe/d) | 269 | 176 | 268 | 184 | 256 | 171 |

***2002 vs 2001 – Production added $10 million to net income***

2002 production before royalties grew modestly over 2001 volumes. A 2% increase in crude oil volumes was partially offset by a 5% decrease in natural gas volumes.

MASILA BLOCK IN YEMEN

- Maintained production through our on going development drilling, water handling and throughput expansions.
- Experienced minor delays in tanker loadings but no impact on production or cash flow when the supertanker Limburg was damaged near our Ash Shihr export terminal.
- In 2003, we expect to maintain production through continued infill drilling, facility enhancements and exploration focused on deeper targets.

CANADA

- We invested $240 million or about 15% of our total capital expenditures in 2002 to mitigate production declines.
- We are focused on our highest-return projects including Hay, while we develop new sources of production in synthetic crude and coal bed methane.
- Hay set a new 8,000 barrel per day production record in 2002.

GULF OF MEXICO

- Production decreased due to development delays, weather-related shut-ins and production declines on some of our shelf properties.
- Poor weather in the third and fourth quarters, including tropical storm Isidore and Hurricane Lili, caused temporary shut-in of production, a 6-week delay at Aspen and damage to our Eugene Island 295 production platform.
- All production, except Eugene Island 295, was restored in the fourth quarter.
- Our Eugene Island 295 exploitation program was in progress at the time of the storm; the field has been shut-in since October but is expected to return to producing status during the first quarter of 2003.
- Aspen's first well came onstream in early December and the second well in late December. We are ramping up production to expected rates of 15,000 equivalent barrels per day net to us.
- With Aspen onstream for the full year, we expect 2003 production before royalties to increase by 65% to 46 mboe/d.

BUFFALO OFFSHORE AUSTRALIA

- Completed successful two-well infill drilling program that added incremental production and reserves.
- Exited 2002 at 10,000 barrels per day; we expect Buffalo to be fully depleted in 2004.

EJULEBE OFFSHORE NIGERIA

- Strong 2002 production as the reservoir continued to perform better than anticipated.
- Exited 2002 at 4,700 barrels per day with water-cuts increasing; we expect Ejulebe to be depleted in 2004.

SYNCRUDE

- Extended maintenance turnaround, unplanned coker maintenance and sulfur dioxide emission restrictions reduced volumes during the first half of the year.
- December production of 19,100 barrels per day set a new monthly record.

***2001 vs 2000 – 5% production growth added $153 million to net income***

- Masila set an annual production record for the sixth consecutive year with gross rates of 227,500 barrels per day.
- In Canada, our exploitation activities included successful optimization of our Hay assets with the doubling of production to an annual average of 5,400 barrels per day.
- Gulf of Mexico natural gas production grew 7% with the fourth quarter acquisitions of Vermilion 76 and Eugene Island 295 and with successful exploitation of our shallow-water assets.
- Australian crude oil production remained stable as the acquisition of the remaining 50% interest in Buffalo offset natural production declines.

## Commodity Prices

(Prices based on working interest production before royalties)

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| **Crude Oil** (Cdn$/bbl) | | | |
| West Texas Intermediate (US$/bbl) | 26.09 | 25.97 | 30.21 |
| Differentials (US$/bbl): | | | |
| Masila | 1.41 | 3.29 | 2.82 |
| Heavy Oil | 6.49 | 10.68 | 8.06 |
| Producing Assets: | | | |
| Yemen | 38.80 | 35.05 | 40.53 |
| Canada | 31.13 | 24.86 | 33.49 |
| United States | 38.88 | 38.35 | 44.18 |
| Syncrude | 40.89 | 39.90 | 44.84 |
| Australia | 40.30 | 38.71 | 41.05 |
| Other Countries | 38.96 | 37.37 | 40.12 |
| Corporate Average (Cdn$/bbl) | 37.13 | 33.10 | 39.23 |
| **Natural Gas** (Cdn$/mcf) | | | |
| New York Mercantile Exchange (US$/mmbtu) | 3.37 | 4.00 | 4.31 |
| Canada | 3.57 | 5.02 | 4.38 |
| United States | 5.29 | 6.66 | 6.90 |
| Corporate Average (Cdn$/mcf) | 4.25 | 5.69 | 5.42 |

***2002 vs 2001 – Higher realized prices added $76 million to net income***

CRUDE OIL PRICES

- Average WTI was largely unchanged but narrow oil differentials added $180 million to net income, increasing our realized price 11%.
- At the beginning of 2002, WTI was US $19.73 per barrel strengthening throughout the year to close at US $31.20.
- Early second quarter strength was driven by uncertainty in the Middle East, OPEC's maintenance of production quotas and the threat of war between Iraq and the US.
- WTI slid modestly early in the fourth quarter as quota cheating by OPEC members increased and the war premium disappeared with Iraq cooperation.
- Despite the reduction of the war premium, WTI strengthened late in the year as supply disruptions took place in Venezuela and OPEC took steps to shore-up production quotas.

NARROW DIFFERENTIALS

- The strength of Brent relative to WTI combined with a short-term premium for Masila mid-year, resulted in a narrower Masila differential. Low inventory levels in Europe kept the Brent-WTI differential narrow throughout most of the year.
- Heavy oil narrowed early in the year due to reduced supply, continued narrow into the summer months due to normal seasonal demand and remained narrow into the winter months due to the Venezuelan supply disruption.
- Realized crude oil prices for Canada and Yemen exceeded 2001 prices by 25% and 11%, respectively.
- We expect the Masila differential to return to historical norms around US $3.00 per barrel in 2003.
- We expect 2003 heavy oil differentials to remain narrow in the near-term due to the ongoing disruptions in Venezuela.

NATURAL GAS PRICES

- Lower gas prices reduced net income by $114 million.
- Prices fell in the first part of 2002 from the record highs of 2001 as gas inventories were higher, but strengthened late in 2002 as cold weather in the eastern US drove up demand and caused supply concerns.
- We expect stronger gas prices in 2003 as production decline rates and a lack of drilling should continue to reduce available supply levels.

***2001 vs 2000 – Lower realized prices reduced net income by $286 million***

- Lower crude oil prices in 2001.
- At the beginning of 2001, WTI was approximately US $29 per barrel and closed the year at US $19.40 per barrel.
- Sluggish demand after September 11, 2001 and concerns over inventory levels drove prices down late in the year.
- Natural gas prices softened as North American inventories rose.

## Operating Costs

(Unit operating costs based on working interest production before royalties)

| (Cdn$/boe) | 2002 | 2001 | 2000 |
|---|---|---|---|
| Conventional Oil and Gas | | | |
| Yemen | 1.95 | 1.62 | 1.42 |
| Canada | 5.70 | 4.87 | 4.57 |
| United States | 9.09 | 6.01 | 5.00 |
| Australia | 9.76 | 13.50 | 6.92 |
| Other Countries | 6.21 | 8.07 | 7.58 |
| Total Conventional | 4.60 | 3.92 | 3.38 |
| Synthetic Crude Oil | | | |
| Syncrude | 19.09 | 19.43 | 18.36 |
| Total Oil and Gas [1] | 5.48 | 4.88 | 4.22 |

Note:

[1] Operating costs per equivalent barrel are our total oil and gas operating costs divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies. See Reserves, Production and Other Information in Item 1 and 2 in this 10-K for unit operating costs based on our production after royalties.

***2002 vs 2001 – Higher oil and gas operating costs reduced net income by $66 million***

Conventional operating costs increased $0.68 per equivalent barrel:

- Gulf of Mexico was a significant contributor as workovers and repairs on the shelf increased costs and temporarily reduced production. Weather-related shut-ins and storm damage also contributed to the increase. One-time workovers and storm-related costs are not expected to continue in 2003.
- Costs are expected to decrease in 2003 with low-cost production from Aspen making up a larger portion of our total Gulf production.
- In Canada, industry cost pressures and a maturing asset base increased per unit costs. In addition, unexpected turnaround costs at our Balzac gas plant caused a one-time increase in operating costs.
- In Yemen, increased water-handling and waterflood costs as well as one time flood-related costs increased per-unit costs.

- In 2002, our floating production and storage off-loading vessel (FPSO) costs in Australia decreased on a per-unit basis as fixed costs were spread over more barrels and increased production levels attracted a lower throughput cost. This decrease in FPSO unit costs was partly offset by one-time field repair costs.

With respect to synthetic crude oil, our operating costs at Syncrude stabilized in 2002 as second quarter maintenance activities improved reliability and performance.

***2001 vs 2000 - Higher oil and gas operating costs reduced net income by $82 million***

- Conventional operating costs increased $0.54 per equivalent barrel. Industry cost pressures from a sustained period of high commodity prices and maturing assets contributed to the increase.
- Australia's costs increased as fixed costs were spread over fewer barrels of production.
- Maintenance activities and higher energy prices caused an increase in Syncrude's per-unit operating costs.

## Depreciation, Depletion and Amortization (DD&A)

(Based on working interest production before royalties)

| (Cdn$/boe) | **2002** | **2001** | **2000** |
|---|---|---|---|
| Conventional Oil and Gas | | | |
| Yemen | 3.47 | 2.56 | 2.20 |
| Canada | 8.22 | 7.14 | 7.89 |
| United States | 12.74 | 10.59 | 12.70 |
| Australia | 10.45 | 16.61 | 21.05 |
| Other Countries | 13.22 | 15.11 | 15.88 |
| Total Conventional | 6.84 | 5.97 | 6.67 |
| | | | |
| Synthetic Crude Oil | | | |
| Syncrude | 2.13 | 2.03 | 2.23 |
| Total Oil and Gas [1] | 6.55 | 5.73 | 6.41 |

Note:

[1] DD&A per equivalent barrel is our DD&A for oil and gas operations divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

***2002 vs 2001 – Higher oil and gas DD&A reduced net income by $85 million***

Conventional depletion rates increased $0.87 per equivalent barrel:

- Higher 2001 finding and development costs in Canada, Yemen and the Gulf shelf comprise the majority of the increase.
- Changing production mix also contributed as a larger portion of production came from more capital-intensive properties.
- Rates in Australia decreased as reserves were added with our successful infill drilling program.

***2001 vs 2000 – Lower oil and gas DD&A added $38 million to net income***

- Depletion rates for conventional production decreased as reserves were added at low finding and development costs in 2000.

## Exploration Expense

| (Cdn$ millions) | **2002** | **2001** | **2000** |
|---|---|---|---|
| Seismic | 80 | 79 | 74 |
| Unsuccessful Drilling | 63 | 135 | 54 |
| Other | 46 | 51 | 45 |
| Total Exploration Expense | 189 | 265 | 173 |
| | | | |
| Total Exploration Capital | 259 | 411 | 300 |

***2002 vs 2001 - Lower exploration expense added $76 million to net income***

- Pursued exploration activities in Yemen, Nigeria, Brazil, Colombia, the Gulf of Mexico and Canadian natural gas.
- Lower exploration expense as capital spending focused on development of earlier successes.
- Drilled 68% fewer exploration wells.
- Successfully drilled an exploration well at Usan on Block OPL-222.
- Unsuccessful exploration wells include Block 59 in Yemen, Fusa in Colombia, Block BC-20 offshore Brazil and Fergana in the Gulf of Mexico.

***2001 vs 2000 – Higher exploration expense reduced net income by $92 million***

- Higher exploration expense due to our largest-ever exploration program.
- Unsuccessful drilling costs include two high-risk exploration wells: Scout in the deep-water Gulf of Mexico and Kayu Manis, offshore Indonesia.

## OIL AND GAS MARKETING

| (Cdn$ millions) | **2002** | **2001** | **2000** |
|---|---|---|---|
| Revenue | 496 | 438 | 179 |
| Transportation | (423) | (342) | (131) |
| Net Revenue | 73 | 96 | 48 |
| | | | |
| Marketing contribution to Income before Income Tax | 35 | 59 | 23 |
| | | | |
| Physical Sales Volumes (excluding intra-segment transactions) | | | |
| Crude Oil (mboe/d) | 412 | 400 | 294 |
| Natural Gas (mmcf/d) | 2,865 | 2,499 | 1,664 |
| | | | |
| Value-at-Risk | | | |
| Year-end | 19 | 19 | 13 |
| High | 28 | 24 | 13 |
| Low | 12 | 6 | 2 |
| Average | 17 | 13 | 4 |

***2002 vs 2001 – Lower net marketing revenue reduced net income by $23 million***

The energy trading industry experienced many challenges in 2002. Liquidity was at an all-time low following the collapse of Enron and the exposure of questionable accounting and valuation practices by a number of companies. Numerous participants retrenched, consolidated or exited the industry completely. Accounting standard setters and regulators made changes to the rules and practices governing the industry, including improved and more transparent disclosures, as well as changes to the mark-to-market accounting rules, which are described more fully in note 1(r) to our Consolidated Financial Statements.

Our marketing operations had lower net revenue in 2002 compared to 2001 due to:

- Less price volatility in 2002.
- The reduced number of competitors allowed us to increase our marketed volumes over 2001 levels.
- Excluding the one-time gains in the first quarter of 2001, margins grew year over year. We expect margins to continue to grow in 2003 as industry retrenchment continues.

***2001 vs 2000 – Higher net marketing revenue adds $48 million to net income***

- We successfully capitalized on the significant price volatility early in the year.
- Crude oil volumes increased with the acquisition of Northridge Energy Marketing Ltd., which was purchased on July 31, 2000. Northridge marketed approximately 90,000 barrels of oil per day.

## Derivative Energy Contracts

Our marketing operation engages in crude oil and natural gas marketing activities to enhance prices from the sale of our own oil and gas production, and for energy trading. We enter into contracts to purchase and sell crude oil and natural gas. These contracts expose us to commodity price risk between the time contracted volumes are purchased and sold. We actively manage this risk by using energy-related futures, forwards, swaps and options, and by balancing physical and financial contracts in terms of volumes, timing of performance and delivery obligations. However, net open positions may exist, or we may establish them to take advantage of market conditions.

Consistent with our management practices, we account for all derivative energy contracts using mark-to-market accounting, and record the net gain or loss from their revaluation in marketing and other income. The fair value of these instruments is recorded as accounts receivable or payable. They are classified as long-term or short-term based on their anticipated settlement date. On October 25, 2002, as described in note 1(r) to the Consolidated Financial Statements, generally accepted accounting principles followed by energy traders eliminated mark-to-market accounting for inventories. As such, after October 25, 2002, inventories held by our marketing operation are accounted for at the lower of cost or market value.

### *Fair Value of Derivative Energy Contracts*

We value derivative energy trading contracts daily using:

- actively quoted markets such as the New York Mercantile Exchange and the International Petroleum Exchange; and
- other external sources such as independent price publications and over-the-counter broker quotes.

At December 31, 2002, the unrealized fair value of our derivative energy contracts totalled $3 million. The following table shows the valuation methods underlying these contracts together with details of contract maturity:

| (Cdn$ millions) | Maturity | | | | |
|---|---|---|---|---|---|
| | < 1 year | 1-3 years | 4-5 years | > 5 years | Total |
| Prices: | | | | | |
| Actively quoted | 63 | (40) | (13) | - | 10 |
| From other external sources | (67) | 45 | 14 | 1 | (7) |
| Based on models and other valuation methods | - | - | - | - | - |
| Total | (4) | 5 | 1 | 1 | 3 |

Contract maturities vary from a single day up to six years. A large number of our contracts mature in less than one year. Those maturing beyond one year are primarily from natural gas related positions. The relatively short maturity position of our contracts lowers our portfolio risk.

Our accounting policy does not permit us to record income on transportation and inventory using option valuation methods. As a result, we have not been subject to write-downs due to the loss of liquidity and volatility caused by the industry retrenchment in 2002.

### *Changes in Fair Value of Derivative Energy Contracts*

| (Cdn$ millions) | Contracts Outstanding at Beginning of Year | Contracts Entered Into During Year | Total |
|---|---|---|---|
| Outstanding at December 31, 2001 | 19 | - | 19 |
| Change in fair value of contracts: | | | |
| Outstanding at January 1, 2002 | 21 | - | 21 |
| Entered into during 2002 | - | 37 | 37 |
| Net gains realized on positions closed during the year | (44) | (30) | (74) |
| Changes in valuation techniques and assumptions [1] | - | - | - |
| Outstanding at December 31, 2002 | (4) | 7 | 3 |

Note:
[1] Our valuation methodology has been applied consistently year over year.

***Composition of Net Marketing Revenue***

| (Cdn$ millions) | |
|---|---|
| Derivative energy contracts | 58 |
| Non-derivative energy contracts | 15 |
| Net Marketing Revenue | 73 |

Of the $73 million net marketing revenue recognized during 2002, only a net gain of $3 million is unrealized at December 31, 2002.

### Non-derivative Energy Contracts

Our marketing operation also manages various natural gas transportation commitments on behalf of our Canadian oil and gas business and a number of third-party customers. These activities optimize our trading operations. The related commitments are outlined in the Contractual Obligations, Commitments and Contingencies section. We earned $15 million from our non-derivative energy activities in 2002.

## CHEMICALS

| (Cdn$ millions) | **2002** | **2001** | **2000** |
|---|---|---|---|
| Net Sales | 367 | 373 | 336 |
| Sales Volumes (thousand short tons) | | | |
| Sodium chlorate | 454 | 457 | 462 |
| Chlor-alkali | 375 | 365 | 407 |
| Operating Profit [1] | 100 | 99 | 96 |
| Operating Margin (%) | 27 | 27 | 29 |
| Chemicals contribution to Income before Income Taxes | 27 | 47 | 39 |
| Capacity Utilization (%) | 85 | 89 | 92 |

Note:
1 Net sales less operating costs and transportation.

***2002 vs 2001 – Chemicals operating profit adds $1 million to net income***

We faced many challenges in 2002:

- Slow economic recovery in North America placed downward pressure on sodium chlorate volumes and eroded market prices.
- Increasing energy costs in Louisiana put pressure on our Taft plant, and as a result, the assets have recently been temporarily idled while we review alternatives to manage these costs.

During 2002, margins remained strong due to lower overall energy costs and the shifting of production from higher-cost to lower-cost facilities following the expansion of our Brandon and Brazil facilities. The expansion of these plants and the shifting of production to lower cost facilities increased our depreciation.

Demand in 2003 is expected to improve for sodium chlorate as the economy recovers. We expect to take advantage of the recovery with a full year of production from our Brandon and Brazil expansions. We are continuing to take steps towards improving our overall cost structure in North America.

***2001 vs 2000 – Chemicals operating profit adds $3 million to net income***

- Sales revenue increased 11% as price increases more than offset recessionary conditions in North America.
- Operating costs as a percentage of sales were consistent with 2000 as high natural gas prices fell late in 2001.

## CORPORATE EXPENSES

### General and Administrative

| (Cdn$ millions) | 2002 | 2001 | 2000 |
|---|---|---|---|
| General and Administrative | 152 | 136 | 117 |

***2002 vs 2001 – Higher costs reduced net income by $16 million***

- 70% of the increase was due to higher staffing levels, associated with our record capital investment program and growth in our marketing operations.
- Increased pension expense due to poor equity market performance.
- We also experienced higher building lease costs and incremental expenses associated with our stock appreciation rights plan.

***2001 vs 2000 – Higher costs reduced net income by $19 million***

- 60% of the increase related to the expansion of our marketing operations in Calgary and Singapore.
- Remainder was due to increased staffing levels associated with a larger capital investment program.

### Interest

| (Cdn$ millions) | 2002 | 2001 | 2000 |
|---|---|---|---|
| Interest | 140 | 112 | 132 |
| Less: Capitalized Interest | (31) | - | - |
| Net Interest Expense | 109 | 112 | 132 |

***2002 vs 2001 – Lower interest expense added $3 million to net income***

- Total interest costs increased $28 million as a result of the higher borrowing rate on our new 30-year notes.
- Net interest decreased as we capitalized interest on our major development projects.

***2001 vs 2000 – Lower interest expense added $20 million to net income***

- Lower interest rates and debt levels contributed to decrease from 2000.

### Income Taxes

***2002 vs 2001 – Effective tax rate declines from 40% to 34%***

Rate decreased due to:

- lower federal and provincial statutory tax rates for Canadian non-oil and gas operations;
- higher portions of income coming from international operations where rates are lower; and
- non-taxable capital gain on the sale of our Moose Jaw operations.

The majority of our 2002 current income taxes were paid in Yemen and Australia. Current taxes include cash taxes in Yemen of $207 million (2001 - $191 million; 2000 - $217 million). In 2002, federal and provincial capital taxes were payable in Canada. In 2001 and 2000, alternative minimum tax was payable in the US.

### Gain or Loss on Disposition of Assets

Net loss in 2002 includes:

- $13 million gain on the sale of our asphalt operation in Moose Jaw, Saskatchewan for proceeds of $27 million plus working capital; and
- $21 million loss on the sale of a non-operated property by our Canadian oil and gas business segment for proceeds of $14 million.

Gains in 2001 related to the disposition of minor properties in Australia and the United States. In 2000, gains related to the exchange of our 15% interest in oil and gas assets in Ecuador for Occidental's 15% minority interest in our chemicals operations and the disposition of non-core assets in Canada.

## LIQUIDITY

### Capital Structure

| (Cdn$ millions) | 2002 | 2001 |
|---|---|---|
| Bank Debt | - | 424 |
| Senior Public Debt | 1,844 | 1,060 |
| | 1,844 | 1,484 |
| Less: Working Capital | 69 | 24 |
| Net Debt [1] | 1,775 | 1,460 |
| Shareholders' Equity [2] | 2,348 | 1,904 |

Notes:
[1] Long-term debt less working capital.
[2] Included in shareholders' equity are preferred securities of $724 million (US $476 million). Under US generally accepted accounting principles, these are considered long-term debt.

Our business strategy is focused on value-based growth through full-cycle exploration and development, supplemented by strategic acquisitions when appropriate. We rely on operating cash flow and borrowings under committed credit facilities and public debt, including preferred securities, for our liquidity and capital requirements. We build our opportunity portfolio to provide a balanced mix of short-term, mid and longer-term growth. This enables us to generate ongoing sustainable operating cash flows.

We enhanced our capital structure in 2002:

| | |
|---|---|
| **Shareholders' equity** | Continued to strengthen with strong 2002 operating and financial results. |
| **US $500 million of 7.875% debt** | Issued in March 2002 and maturing in 30 years. Proceeds used to repay existing bank debt and fund a portion of our capital investment program. |
| **Committed bank facilities of $1,576 million** | All undrawn at year-end and available until 2007. |
| **$500 million Canadian shelf prospectus** | Available until May 2003. |
| **US $500 million US shelf prospectus** | Available until May 2004. |
| **Favourable debt maturities** | Over the next five years, $355 million matures in 2004, $108 million in 2006 and $150 million in 2007. |
| **Increased term to maturity** | Increased the average term to maturity of our debt to 18 years, an increase of 8 years from the end of 2001. |
| **$724 million of Preferred Securities** | Provide fixed-rate financing for another 45 years but can be redeemed at par commencing in October 2003 ($393 million) and February 2004 ($331 million). The Preferred Securities are subordinated to Senior Debt and interest payments may be deferred for up to five years. Interest and principal can be settled with common shares. |

The change in net debt in 2002 and 2001 resulted from:

| (Cdn$ millions) | 2002 | 2001 |
|---|---|---|
| Capital Expenditures | 1,625 | 1,404 |
| Cash Flow from Operations | (1,383) | (1,423) |
| Dividends on Preferred Securities and Common Shares | 109 | 107 |
| Foreign Exchange | - | 57 |
| Proceeds on Disposition of Assets | (49) | (5) |
| Other | 13 | (24) |
| Increase in Net Debt | 315 | 116 |

***2002 - $315 million increase in net debt***

- Capital expenditures and dividend payments exceeded cash flow from operations.

***2001 - $116 million increase in net debt***

- Capital expenditures and dividend payments exceeded cash flow from operations.
- The decline in the Canadian dollar relative to the US dollar also increased net debt.

In 2002, we had working capital of $69 million compared to $24 million in 2001. Our large natural gas storage position at year end caused the increase. The value of this natural gas position has been fixed through financial derivatives. At December 31, 2002, we sold $178 million of accounts receivable proceeds (2001 - $100 million) to minimize our total cost of financing.

Our future debt levels are primarily dependent on our operating cash flows and our capital investment programs. Currently, we expect our 2003 capital program and dividend requirements to be funded by cash flow from operations. Our 2003 operating cash flows assume WTI is US $23 per barrel and natural gas is US $3.50 per mcf for the remainder of year. For every US $1 change in WTI or every US $0.50 change in natural gas, we expect our cash flow from operations to change by $67 million and $61 million, respectively. In addition, we have $1.6 billion of additional unsecured credit facilities to draw on.

We declared common share dividends of $0.30 per common share in each of the last three years.

## Leverage Statistics

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Net Debt to Cash Flow [1] (times) | 1.4 | 1.1 | 0.9 |
| Interest Coverage [2] (times) | 10.7 | 13.7 | 12.9 |
| Fixed Charge Coverage [3] (times) | 7.2 | 8.4 | 8.5 |

Notes:

1 Cash Flow comprises cash flow from operations after dividends on Preferred Securities. Under US regulations, preferred securities are considered long-term debt. Our net debt to cash flow would be 1.9 times (2001 - 1.6; 2000 - 1.4).

2 Cash flow from operations before interest expense divided by total interest.

3 Cash flow from operations before interest expense divided by total interest plus dividends on Preferred Securities.

Our net debt is equal to 1.4 times our 2002 cash flow from operations after dividends on preferred securities. This, together with our coverage ratios, provides us with sufficient financial flexibility and liquidity to pursue our business strategy.

## Credit Ratings

Currently, our senior debt is rated BBB-mid by Dominion Bond Rating Service, BBB by Standard and Poor's and Baa2 by Moody's Investor Service, Inc. In addition, all rating agencies currently have our rating outlook as stable. Our strong financial results, low historical finding and development costs, ample liquidity and financial flexibility will continue to support our current credit rating.

## Financial Assurance Provisions in Commercial Contracts

The commercial agreements our marketing operations enter into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements generally provide for some type of collateral in the event of deterioration in the creditworthiness of the buyer. Credit ratings are frequently used in the agreements to provide an objective measure of creditworthiness, with the agreement typically requiring the posting of collateral (in the form of either cash or a Letter of Credit), if a buyer's credit rating drops below investment grade. Based on contracts in place and commodity prices at December 31, 2002, we would be required to post collateral of $210 million in the event of a downgrade to non-investment grade. This obligation is reflected in our balance sheet. The posting of collateral merely accelerates the payment of such amounts. Our committed undrawn credit facilities of $1.6 billion adequately cover any potential collateral requirements. Just as we may be required to post collateral in the event of a downgrade below investment grade, we have similar provisions in many of our customer contracts that allow us to demand certain customers post collateral with us if they are downgraded to non-investment grade.

## OUTLOOK FOR 2003

### 2003 Capital Investment Program

| (Cdn$ millions) | Exploration | Development | Other | Total |
|---|---|---|---|---|
| Yemen | 17 | 234 | - | 251 |
| Canada | 40 | 328 | - | 368 |
| United States | 136 | 182 | - | 318 |
| Syncrude | - | 176 | - | 176 |
| Australia | 3 | 3 | - | 6 |
| Other | 90 | 43 | - | 133 |
| Total Oil & Gas | 286 | 966 | - | 1,252 |
| Chemicals | - | - | 46 | 46 |
| Marketing, Corporate and Other | - | - | 34 | 34 |
| Total | 286 | 966 | 80 | 1,332 |

Our 2003 capital program of $1.3 billion, our third largest ever, will build on the success of last year. Our solid capital structure and surplus liquidity will support this program. The following items show the expected distribution of our 2003 capital investment program:

- 40% to sustain and grow production and cash flow from our core assets;
- 30% to continue progress on our major development projects for near to mid-term growth; and
- 20% on exploration to test almost 900 million barrels of unrisked resource potential for long-term growth.

This program is consistent with our strategy to grow reserves and production primarily through the drill bit.

### Core Asset Maximization

Our focus is to maintain production from our core assets to extract their maximum value without overcapitalizing.

#### Yemen

- We will continue exploring deeper carbonate sections, further develop the main Qishn horizons and continue waterflood projects on the secondary horizons to maintain production at 226,900 barrels per day.

#### Gulf of Mexico

- We expect production growth from continued exploitation of our Vermilion 76, Eugene Island 257/258, Eugene Island 295 and Eugene Island 18 properties and a full year of operations from deep-water Aspen.

#### Canada

- About 14% of our total 2003 investment program will be invested in Canadian conventional exploration and production.
- We will focus on projects that provide the highest returns on invested capital, while we transition to new sources of production growth such as synthetic crude oil, coal bed methane and high-impact gas exploration.

#### Daily Production

We expect our core assets to generate daily production before royalties of between 270,000 and 280,000 equivalent barrels in 2003. While production before royalties will increase modestly, production after royalties is estimated to grow 6% to 10%, to between 190,000 and 196,000 equivalent barrels per day, with significant new royalty-free production from Aspen. Actual production rates will depend upon numerous factors including commodity prices, the level of capital expenditures, drilling success and well performance.

| (mboe/d) | 2003 Estimate | |
|---|---|---|
| | Before Royalties | After Royalties |
| Canada | 77 - 82 | 61 - 64 |
| Yemen | 118 - 119 | 60 - 61 |
| United States | 46 - 52 | 39 - 45 |
| Syncrude | 17 - 18 | 17 - 18 |
| Other International | 12 - 16 | 11 - 14 |
| | 270 - 280 | 190 - 196 |

Over the next five years, production after royalties is expected to grow as our production grows in the deep-water Gulf of Mexico and synthetic crude oil. Since these projects have low or no royalties, lower costs and ultimately higher returns than our current producing assets, this changing production mix will improve profitability, despite lower anticipated oil prices. Using the mid-point of our production range and assuming WTI averages US $23 per barrel and gas prices average US $3.50 per thousand cubic feet in 2003, we expect cash flow from operating activities of approximately $1.3 billion. For every dollar change in WTI in 2003, our cash flow will change by $67 million. For every $0.50 change in our North American natural gas price in 2003, our cash flow will change by $61 million.

### Chemicals and Marketing

We expect continuing strong performance from our chemicals and marketing businesses in 2003. In our chemicals operation, increased demand for sodium chlorate, higher margins for chlor-alkali, and operational efficiencies resulting from our Brandon and Brazil expansions should improve cash flow. Our oil and gas marketing business is growing in the fee for service segment and we expect attractive margins, as many competitors have exited the sector.

### Major Development Projects

Details of the investment activities for each project are included in the 2002 Capital Investment section in this MD&A. Together these projects are expected to add 55,000 to 65,000 equivalent barrels of daily production by 2007 as they become core assets.

### Strong Grass Roots Exploration

Our 2003 exploration program is our highest quality ever as we plan to drill prospects offsetting existing discoveries and extensions of play types we know well. We expect to drill up to 18 high-impact wells. Our plans include:

#### Gulf of Mexico

- We will invest approximately one-half of our exploration capital here.
- We plan to drill at least five high-impact exploration wells, including the deep-water Gotcha prospect in the Alaminos Canyon area. This prospect directly offsets the recently discovered Great White discovery. We will also drill prospects in the Green Canyon and Garden Banks areas, and a Deep Miocene gas prospect on the shelf.
- We plan to drill additional wells depending upon success and partner priorities.

#### Other Exploration

- In Yemen, we will continue interpreting seismic data on our exploration blocks and drill at least one exploration well.
- Offshore Brazil, we plan to drill an exploration well on Block BC-20 in the Campos Basin.
- In Canada, we will focus exploration on gas prospects in the foothills of northwestern Alberta and in northeastern British Columbia.

## CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

We have assumed various contractual obligations and commercial commitments in the normal course of our operations and financing activities. Contractual obligations include both financial and non-financial obligations. Financial obligations are considered to represent known future cash payments that we are required to make under existing contractual arrangements, such as debt and lease arrangements. Non-financial obligations represent contractual obligations to perform specified activities, such as work commitments. Commercial commitments represent contingent obligations that become payable only if certain pre-defined events occur.

### Contractual Cash Obligations and Other Commercial Commitments

| (Cdn$ millions) | Payments[1] | | | | |
|---|---|---|---|---|---|
| | Total | <1 year | 1-3 years | 4-5 years | >5 years |
| Long-Term Debt [1] | 1,844 | - | 355 | 258 | 1,231 |
| Operating Leases | 257 | 50 | 73 | 34 | 100 |
| Transportation Commitments | 428 | 180 | 72 | 63 | 113 |
| Work Commitments | 166 | 155 | 11 | - | - |
| Other | 9 | 7 | 2 | - | - |
| Total | 2,704 | 392 | 513 | 355 | 1,444 |

Notes:

[1] Payment obligations are not discounted and do not include related interest, accretion or dividends.

- Long-term debt amounts are included in our December 31, 2002 Consolidated Balance Sheet. Under US GAAP, $751 million of Preferred Securities due in 2047 and 2048 would be included in long-term debt. The fair value of these securities is $756 million at December 31, 2002.
- Operating leases include leases for office space, rail cars, vehicles and the lease of the FPSO in Australia.
- Our marketing operation manages various natural gas transportation commitments on behalf of our Canadian oil and gas business and a number of third-party customers. These activities help to optimize our trading operations.
- Work commitments include non-discretionary capital spending related to drilling and seismic commitments in our international operations and development commitments at Gunnison and Syncrude. The remainder of our capital spending in 2003, as discussed in the 2003 Outlook section in this MD&A, is discretionary.

### Contingencies

See note 10 to the Consolidated Financial Statements in Item 8, which is incorporated herein by reference for a discussion of our contingencies.

## BUSINESS RISK MANAGEMENT

The oil and gas industry is highly competitive, particularly in the following areas:

- searching for and developing new sources of crude oil and natural gas reserves;
- constructing and operating crude oil and natural gas pipelines and facilities; and
- transporting and marketing crude oil, natural gas and other petroleum products.

Our competitors include major integrated oil and gas companies and numerous other independent oil and gas companies.

The pulp and paper chemicals market is also highly competitive. Key success factors are:

- price and product quality;
- logistics and reliability of supply; and
- technical service.

We are one of the largest producers of sodium chlorate in North America and have continent-wide supply capability.

### Operational Risk

Acquiring, developing and exploring for oil and natural gas involves many risks. These include:

- encountering unexpected formations or pressures;
- premature declines of reservoirs;
- blow-outs, equipment failures and other accidents;
- craterings and sour gas releases;
- uncontrollable flows of oil, natural gas or well fluids;
- adverse weather conditions; and
- environmental risks.

Although we maintain insurance according to customary industry practice, we cannot fully insure against all of these risks. Losses resulting from the occurrence of these risks could have a material adverse impact.

Our future crude oil and natural gas reserves and production, and therefore our operating cash flows and results of operations, are highly dependent upon our success in exploiting our current reserve base and acquiring or discovering additional reserves. Without reserve additions, our existing reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our oil and natural gas reserves will be impaired.

### Uncertainty of Reserve Estimates

Oil and gas reserve estimates are integral to making investment decisions regarding oil and gas properties, such as whether development should proceed or enhanced recovery methods should be undertaken. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves, including many factors beyond our control. The reserve data included in the Supplementary Financial Information in the Form 10-K represents estimates only.

In general, estimates of economically recoverable oil and natural gas reserves and future net cash flows are based on a number of variable factors and assumptions, such as:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe that the factors and assumptions used in estimating reserves are reasonable based on the information available to us at the time the estimates were prepared. Actual results could vary considerably, which could cause material variances in the following:

- estimated quantities of proved oil and natural gas reserves in aggregate and for any particular group of properties;
- reserve classification based on risk of recovery;
- future net revenues, including production, revenues, taxes, and development and operating expenditures; and
- financial results including the annual rate of depletion and recognition of property impairments.

Management is responsible for estimating the quantities of proved oil and natural gas reserves. Estimates are prepared annually for each property by the reservoir engineer associated with the property. Senior management, including the Chief Executive Officer and Chief Financial Officer, meet with the reserves managers for each division to review the estimates and changes therein.

We assess 100% of our reserve estimates internally each year. In addition, our reserve estimates are assessed annually by independent qualified consultants. Generally, the consultants assess at least 80% of our reserves. Given that the reserves are estimates based on numerous assumptions and interpretations, differences within 10% are considered to be immaterial. Differences greater than 10% are resolved.

The Board of Directors has established a Reserves Review Committee (Reserves Committee) to assist the Board and the Audit and Conduct Review Committee of the Board in fulfilling their oversight responsibilities with respect to the annual review of our oil and gas reserves. The Reserves Committee is comprised of three or more directors, the majority of whom must be independent, and each must have a working familiarity with estimating oil and gas reserves. The Reserves Committee meets with management periodically to review the reserves process, results and related disclosures. The Reserves Committee also meets with the consultants independent of management to review such things as the scope of their work, their access to sufficient information, the nature and satisfactory resolution of any differences of opinion, and their independence.

The estimated discounted future net cash flows from estimated proved reserves included in the Supplementary Financial Information in the Form 10-K are based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows will also be affected by factors such as actual production levels and timing, and changes in governmental regulation or taxation and may differ materially from such estimates. See the Critical Accounting Policies section of this MD&A for a complete discussion of the impact of changes in our reserve estimates.

## Political Risk

We operate in numerous countries, some of which may be considered politically and economically unstable. Our operations and related assets are subject to the risks of actions by governmental authorities, insurgent groups or terrorists. We conduct our business and financial affairs to protect against political, legal, regulatory and economic risks applicable to operations in the various countries where we operate. However, there can be no assurance that we will be successful in protecting ourselves from the impact of these risks.

In October 2002, there was an explosion and fire aboard the supertanker Limburg, which was inbound for our Ash Shihr export terminal in Yemen. Our Masila block operations were largely unaffected by this. Tanker loadings were delayed while our tugboat secured the Limburg to prevent it from running aground. Loading then resumed and oil exports continued as scheduled. This had no impact on our production or cash flows.

Our Masila operations are important to Yemen, providing 50% of the country's oil production. We are a responsible member of the Yemeni community; we build relationships with its members and involve them in key decisions that impact their lives. We also ensure that they benefit from our presence in their country. Our strong relationship with the people and Government of Yemen has allowed us to operate there without interruptions for almost 13 years and we anticipate this continuing.

Our practices have enabled us to operate successfully, not only in Yemen, but also other parts of the world. We have developed excellent practices to manage the risks successfully.

## Environmental Risk

Environmental risks inherent in the oil and gas and chemicals industries are becoming increasingly sensitive as related laws and regulations become more stringent worldwide. Many of these laws and regulations require us to remove or remedy the effect of our activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by the disposal or release of specified substances.

We manage our environmental risks through a comprehensive and sophisticated Safety, Environmental and Social Responsibility (SESR) Management System that meets or exceeds ISO14001 criteria and those of similar management systems. Overall guidance and direction is provided by the SESR Committee of the Board of Directors. In addition, senior management, including the CEO and CFO, regularly meets with SESR management to review and approve SESR policies and procedures, provide strategic direction, review performance and ensure that corrective action is taken when necessary. We develop and implement proactive and preventative measures designed to reduce or eliminate future environmental liabilities, we are prudent and responsible in our management of existing environmental liabilities, and we continuously seek opportunities for performance improvement. In addition, we maintain an ongoing awareness of external trends and emerging issues. These actions provide assurance that we meet or exceed appropriate environmental standards worldwide.

- At December 31, 2002, $205 million has been provided in the Consolidated Financial Statements for future dismantlement and site restoration costs, which are currently estimated to be approximately $544 million for all of our oil and gas and chemicals facilities.
- During 2002, we recorded a provision for future dismantlement and site restoration costs of $43 million (2001 - $45 million; 2000 - $37 million).
- Actual site remediation expenditures for the year were $20 million (2001 & 2000 - $24 million). We anticipate actual site remediation expenditures in 2003 to approximate 2002 levels.
- We perform periodic internal and external assessments of our operations and adjust our estimates and annual provision accordingly.
- During 2002, we conducted an external audit of our management system for safety, environment and social responsibility issues. In general, the review was very positive and the few minor recommendations for improvement are being implemented.

## Kyoto Protocol

Canada was one of 160 countries that adopted the Kyoto Protocol in December 1997. This international treaty establishes commitments to reduce emissions of greenhouse gases (GHG) that are believed to be responsible for increasing the surface temperatures of the Earth and affecting the global climate. The Protocol obliges approximately 38 countries (the Annex 1 countries) to meet national targets that range from an increase of 10% to a reduction of 8% over a 1990 base. The overall reduction averages 5%, and these commitments are to be met during the "first commitment period" of 2008 to 2012. Canada committed to a 6% reduction over the 1990 base when it signed the Kyoto Protocol in April 1998. Economic modelling studies have shown that if emission reductions are met through domestic action in Annex 1 countries alone, there will be severe negative impacts to these countries' economies, and in particular those such as Canada whose economies are resource and energy intensive. The US Government's decision to withdraw from the Kyoto Protocol has serious implications for Canada in the context of a continental or hemispheric energy market, but we expect that the US will develop a response to GHG strategies perhaps using the NAFTA model.

Nexen has been continually assessing, for over 8 years, the impact of climate change developments on our various business interests. We have created a senior management committee (The Climate Change Steering Group) to consider national and international developments; hear from leading experts with respect to science, business and risk issues; and consider investment opportunities. As more details of Canada's domestic program have become available we have undertaken cost analyses based on several carbon price and policy scenarios. While the government has made concessions respecting price (a cap of $15 per tonne) and volumes (a cap of 55 megatonnes for large industrial emitters), much uncertainty remains for those investing in large, capital-intensive projects. We have recreated a 1990 baseline and track and report our direct and indirect emissions and GHG abatement/management activities via the Voluntary Challenge and Registry (VCR). Our 2001 progress report is now posted on the VCR website and the report shows further progress has been made toward reduction of our $CO_2$ emissions and energy inputs per unit of production.

Nexen has looked to GHG emission reduction and to offset investments. In 1995, we started capturing, compressing and selling methane gas from our Canadian heavy oil operation instead of venting it to the atmosphere. Last year, we captured about 950,000 tons of carbon dioxide equivalent (1,900,000 tons in total since 1995); as a result, emissions in 2001 from our Canadian operations were essentially the same as they were in 1990, despite growing production volumes.

As a Canadian-based international oil and gas exploration and production company, we have worked closely with the Canadian Clean Development Mechanism/Joint Implementation Office of the Department of Foreign Affairs and International Trade to ensure that Canadian companies get access to low cost/high quality carbon offset investments. We continue to investigate carbon-offset opportunities in each of our core countries in the belief that there may be synergies between our oil and gas activities and carbon investments. Investment opportunities considered to date have included biological sequestration, renewable energy, process efficiency, flare and fugitive emission reduction projects and fuel switching. We have invested in a carbon sequestration project in Belize and a gasified power co-generation facility at our Balzac gas plant. Both investments were expected to deliver significant offsets, but may not provide the anticipated results due to evolving domestic and international policies. We are also an investor in several research and development projects investigating the technical and economic issues associated with geological storage of $CO_2$, including the use of $CO_2$ for enhanced coal bed methane recovery.

We continue to evaluate emission reduction and $CO_2$ offset investment opportunities. However, to date we have received no assurances from the federal or provincial governments that credit will be given for actions already taken to reduce direct emissions (i.e. methane previously vented from casing and tankage) and indirect emissions (i.e. electricity from utilities). Further investment opportunities will be considered against the risk of this evolving policy framework and credit for early action. We continuously review the feasibility of new and ongoing projects with respect to current social, political and economic factors and will continue to take policy and requirements with respect to GHG emissions into account when conducting these feasibility reviews.

We are committed to the principles of full disclosure and will continue to keep our stakeholders apprised of how these issues affect us, when reasonably determinable.

## MARKET RISK MANAGEMENT

We are exposed to all of the normal market risks inherent within the oil and gas and chemicals business, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We manage our operations in a manner intended to minimize our exposure, as described in note 6 to the Consolidated Financial Statements, which is incorporated by reference here.

### Sensitivities

| (Cdn$ millions) | Cash Flow | Net Income |
|---|---|---|
| Estimated 2003 impact: | | |
| Crude Oil - US $1.00/bbl change in WTI | 67 | 49 |
| Natural Gas - US $0.50/mcf change | 61 | 38 |
| Foreign Exchange - $0.01 change in US to Cdn Dollar | 23 | 11 |
| Interest Rates - 1% change | 3 | 2 |

### Commodity Price Risk

Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals.

To a lesser extent we are also exposed to natural gas price movements. Natural gas prices are generally influenced by North American supply and demand, and to a lesser extent local market conditions.

#### Non-Trading Activities

The majority of our production is sold under short-term contracts, exposing us to short-term price movements. The other energy contracts, we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. At times, we actively manage these risks by using commodity futures, forwards, swaps and options.

During 2002 and 2001, we purchased fixed-to-floating swaps to modify the terms of certain fixed-price natural gas contracts as we prefer to receive an index-based price for our natural gas. Under the terms of these contracts, we must deliver four million cubic feet per day of natural gas to counterparties at prices ranging from $3.06 to $6.08 per thousand cubic feet. On settlement, we will receive or pay cash for the difference between the contract and floating rates on the affected volumes. These swaps expire in 2003.

During 2001 and 2000, we purchased put options to establish a floor for the price of crude oil, in order to mitigate the impact of potential crude oil price declines. The put options effectively provided a minimum price per barrel equal to the contract strike price for all hedged volumes if WTI crude oil price averaged less than the strike price for the contract period. The contracts expired unexercised, as WTI did not average less than the strike price during the contract period.

### Trading Activities

Our marketing operation is involved in the marketing and trading of crude oil and natural gas, through the use of both physical and financial contracts (energy trading activities). These activities expose us to commodity price risk. Open positions exist where not all contracted purchases and sales have been matched, in order to take advantage of market movements. These net open positions allow us to generate income, but also expose us to risk of loss due to fluctuating market prices (market risk) and credit exposure. We control the level of market risk through daily monitoring of our energy-trading portfolio relative to:

- prescribed limits for Value-at-Risk (VaR);
- nominal size of commodity positions;
- periodic loss; and
- stress testing.

VaR is a statistical estimate that is reliable when normal market conditions prevail. Our VaR calculation estimates the maximum probable loss given a 95% confidence level that we would incur if we were to unwind our outstanding positions over a two-day period. We estimate VaR using the Variance-Covariance method based on historical commodity price volatility and correlation inputs. Our estimate is based upon the following key assumptions:

- changes in commodity prices are normally distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

If a severe market shock was to occur, the key assumptions underlying our VaR estimate could be violated and the potential loss could be greater than our VaR estimate. There were no changes in the methodology we used to estimate VaR in 2002.

Stress testing complements our VaR estimate and measures the potential impact of low probability extreme market shocks on the value of our energy-trading portfolio. Stress test results are used to ensure that we are not exposed to large losses that might result from infrequent but extreme market conditions that are not captured by VaR.

We also have formal risk management policies relating to our energy trading activities that have been approved by our Board of Directors. Market and credit risks are monitored daily by a risk group that operates independently and ensures compliance with our risk management policies. The Finance Committee of the Board of Directors and our Risk Management Committee monitor our exposure to the above risks and review the results of energy trading activities on a regular basis.

## Foreign-Currency Rate Risk

A substantial portion of our operations are denominated in or referenced to US dollars. These activities include:

- prices received for sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses related to our oil and gas and chemicals operations outside Canada; and
- short-term and long-term borrowings.

We manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. Since the timing of cash inflows and outflows is not necessarily interrelated, particularly for capital expenditures, we maintain revolving US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We have designated our long-term US-dollar borrowings as a hedge against our US-dollar net investment in foreign operations.

We do not have any material exposure to highly inflationary foreign currencies.

We occasionally use derivative instruments to effectively convert cash flows from Canadian to US dollars and vice versa. Information regarding our foreign currency net investments, borrowings and related derivative instruments is provided in note 6 to the Consolidated Financial Statements.

## Interest Rate Risk

We are exposed to fluctuations in short-term interest rates as a result of the use of floating-rate debt and, to a lesser extent, the use of derivative instruments, as their market value is sensitive to interest rate fluctuations. We maintain a portion of our debt capacity in revolving, floating rate bank facilities with the remainder issued in fixed-rate borrowings. To minimize our exposure to interest rate fluctuations, we occasionally use derivative instruments as described in note 6 to the Consolidated Financial Statements.

At December 31, 2002, we had no floating-rate debt outstanding (2001 - $424 million, 2000 - $430 million).

## Credit Risk

Credit risk is the risk of loss resulting from non-performance of contractual obligations by a customer or counterparty. A substantial portion of our accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. This concentration of risk within the energy industry is mitigated through our broad domestic and international customer base. We are also exposed to possible non-performance by derivative instrument counterparties. We take the following measures to reduce this risk:

- we assess the financial strength of our customer and counterparty base through a rigorous credit process;
- we limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- credit risk exposures, including concentrations of credit, are monitored routinely and reported to our Risk Management Committee and the Finance Committee of the Board;
- we set credit limits based on counterparty credit ratings and internal models, which are based primarily on company and industry analysis;
- we review counterparty credit limits regularly; and
- we use standard agreements that allow for netting of positive and negative exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance. At December 31, 2002:

- 90% of our counterparty exposures are investment grade; and
- only four customers individually made up greater than 5% of our exposure from energy trading activities. All are investment grade.

## CRITICAL ACCOUNTING POLICIES

As an oil and gas producer, there are a number of critical estimates underlying the accounting policies applied in the preparation of our Consolidated Financial Statements. These critical estimates are discussed below.

## Oil and Gas Accounting – Reserves Determination

We follow the successful efforts method of accounting for our oil and gas activities, as described in note 1 to our Consolidated Financial Statements. Successful efforts accounting depends on the estimated reserves we believe are recoverable from our oil and gas assets. The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development and production activities becomes available, and as economic conditions impacting oil and gas prices and cost change. Our reserve estimates are based on current production forecasts, prices and economic conditions. See Business Risk Management for a complete discussion of our reserve estimation process.

Reserve estimates are critical to many of our accounting estimates, including:

- Determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and if not, we expense the costs immediately. In 2002, $189 million of our total $259 million spent on exploration drilling was expensed in the year. If none of our drilling had been successful, our net income would have decreased by $46 million after tax.
- Calculating our unit-of-production depletion and asset retirement obligation rates. Both proved and proved developed reserve[1] estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense and our provision for dismantlement and site restoration. Proved reserves are used where a property is acquired

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[1] "Proved" oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically, as demonstrated by either actual production or conclusive formation tests. "Proved developed" oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

and proved developed reserves are used where a property is drilled and developed. In 2002, oil and gas depletion and oil and gas dismantlement and site restoration costs of $604 million and $43 million, respectively, were recorded in depletion, depreciation and amortization expense. If our reserve estimates changed by 10%, our depletion, depreciation and amortization expense would have changed by approximately $45 million, after tax, assuming no other changes to our reserve profile.

- Assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserve estimates, are discussed below.

As circumstances change and additional data becomes available, our reserve estimates also change, possibly materially impacting net income. Estimates made by our engineers are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although we make every reasonable effort to ensure that our reserve estimates are accurate, the subjective decisions, new geological or production information and changing environment may impact these estimates. Revisions to our reserve estimates can arise from changes in year end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative. During the past three years, revisions have been less than 10% of our total reserves and have been largely related to price changes. Reserves information is shown in the Supplementary Financial Information set out in Item 8 of this 10-K.

It would take a very significant decrease in our proved reserves to limit our ability to borrow money under our term credit facilities, as previously described in Liquidity.

## Oil and Gas Accounting - Impairment

We evaluate our oil and gas properties for impairment if an adverse event or change occurs. Among other things, this might include falling oil and gas prices, a significant revision to our reserve estimates, or significant or adverse political changes. If one of these occurs, we estimate undiscounted future cash flows for affected properties to determine if they are impaired. If the undiscounted future cash flows for a property are less than the carrying amount of that property, we calculate its fair value using a discounted cash flow approach. The property is then written down to its fair value. Our cash flow estimates require assumptions about two primary elements - future prices and reserves.

Our estimates of future prices require significant judgements about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility - over the last five years, prices for WTI and NYMEX gas have ranged from US $10.35/bbl to US $37.80/bbl and US $1.61/mmbtu to US $10.10/mmbtu, respectively. Our forecasts for oil and gas revenues are based on a US $23 per barrel WTI and a US $3.50 per mcf gas price. These prices are derived from a consensus of future price forecasts amongst industry analysts. Our estimates of future cash flows generally assume our long-term price forecast and current operating costs per barrel plus an inflation factor. Given the significant assumptions required and the strong possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate. A change in this estimate would impact all except our chemicals business.

We review all of our oil and gas properties for indications of impairment. Based on this review, we have tested certain oil and gas properties for impairment over the last two years. In each year, we determined that the sum of the expected future cash flows, undiscounted, was greater than the carrying amount of the properties. As a result, no impairment charges were recognized in net income.

If we decreased our US $23 per barrel long-term forecast for WTI crude oil prices by US $1.00-1.50/bbl at December 31, 2002, our initial assessment of impairment indicators would not change. Furthermore, current crude oil prices would have to fall over US $10 per barrel before our assessment would change. Although oil and gas prices fluctuate a great deal in the short-term, they are typically stable over a longer-time horizon. This mitigates the potential for impairment.

It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserve estimate and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test, is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserve estimate decrease would have on our assessment of impairment. We do, however, have confidence in our reserve estimates and we do not expect significant downward revisions in the future.

A substantial increase in our estimated impairment provision would lower our net income. We do not expect any significant impairment given that we expense all unsuccessful exploration wells as they are drilled. This leaves us with very little excess carrying value on our balance sheet.

We have discussed the development and selection of the critical accounting estimates described above with the Audit and Conduct Review Committee of our Board of Directors. The above disclosures have also been discussed with this committee.

## NEW ACCOUNTING PRONOUNCEMENTS

In December 2001, the Canadian Institute of Chartered Accountants (CICA) issued Accounting Guideline 13, "Hedging Relationships" (AcG-13). AcG-13 establishes certain conditions for when hedge accounting may be applied. The guideline is effective for fiscal years beginning on or after July 1, 2003. Adoption of AcG-13 is not expected to have a material impact on our financial position or results of operations.

In September 2002, the CICA approved Section 3063, "Impairment of Long-Lived Assets" (S.3063). S.3063 establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets, and applies to long-lived assets held for use. An impairment loss is recognized when the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The new Section is effective for fiscal years beginning on or after April 1, 2003. Adoption of this Section is not expected to have a material impact on our financial position or results of operations.

In December 2002, the CICA approved Section 3110, "Asset Retirement Obligations" (S.3110). S.3110 requires liability recognition for retirement obligations associated with our property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until we expect to settle the retirement obligation. S.3110 is effective for fiscal years beginning on or after January 1, 2004. The total impact on our financial statements has not yet been determined.

The following standards and revisions issued by the CICA do not impact us:

- Amendments to S.3025 - "Impaired Loans", effective for asset foreclosures on or after May 1, 2003
- Section 3475 - "Disposal of Long-Lived Assets and Discontinued Operations", effective for disposal activities initiated by commitments to plans on or after May 1, 2003.

In June 2001, the US Financial Accounting Standards Board (FASB) issued Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 requires liability recognition for retirement obligations associated with our property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until we expect to settle the retirement obligation. FAS 143 is effective for all fiscal years beginning after June 15, 2002. The impact of adopting this standard is described in note 16(f) to the Consolidated Financial Statements.

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 elaborates on the disclosures we must make about our obligations under certain guarantees that we have issued. It also requires us to recognize, at the inception of a guarantee, a liability for the fair value of the obligations we have undertaken in issuing the guarantee. The initial recognition and initial measurement provisions are to be applied only to guarantees issued or modified after December 31, 2002. Adoption of these provisions will not have a material impact on our financial position or results of operations. The disclosure requirements are effective for annual or interim periods ending after December 15, 2002.

In January 2003, the FASB issued Statement No. 148 "Accounting for Stock-Based Compensation - Transition and Disclosure, an Amendment of FASB Statement No. 123" (FAS 148). FAS 148 amends FAS 123 "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair-value based method of accounting for stock-based employee compensation. In addition, FAS 148 amends the disclosure requirements of FAS 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. FAS 148 has no material impact on us, as we do not plan to adopt the fair-value method of accounting for stock options at the current time. We have included the required disclosures in note 8 to the Consolidated Financial Statements.

The following standards issued by the FASB do not impact us:

- Statement No. 145 – "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" effective for financial statements issued on or after May 15, 2002;
- Statement No. 146 – "Accounting for Costs Associated with Exit or Disposal Activities" effective for exit or disposal activities initiated after December 31, 2002;
- Statement No. 147 – "Acquisitions of Certain Financial Institutions - an Amendment of FASB Statements No. 72 and 144 and FASB Interpretation No. 9" effective for acquisitions on or after October 1, 2002; and
- Interpretation No. 46 – "Consolidation of Variable Interest Entities" effective for financial statements issued after January 31, 2003.

## Item 7(A). Quantitative and Qualitative Disclosures about Market Risk

Please refer to the Business and Marketing Risk Management sections of Item 7 for the required disclosures about Market Risk.

### SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this report, including those appearing in Items 1 and 2 - Business and Properties and Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations, are forward-looking statements.[1] Forward-looking statements are generally identifiable by terms such as "plan", "expect", "estimate", "budget" or other similar words.

These statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. These risks, uncertainties and other factors include:

- market prices for oil, natural gas and chemicals products;
- our ability to produce and transport crude oil and natural gas to markets;
- the results of exploration and development drilling and related activities;
- foreign-currency exchange rates;
- economic conditions in the countries and regions in which we carry on business;
- governmental actions that increase taxes, change environmental and other laws and regulations;
- renegotiations of contracts; and
- political uncertainty, including actions by terrorists, insurgent groups or war.

The above items and their possible impact are discussed more fully in the section, titled "Business Risk Management" and "Market Risk Management" in Item 7.

The impact of any one risk, uncertainty or factors on a particular forward-looking statement is not determinable with certainty as these factors are interdependent and management's future course of action depends upon our assessment of all information available at that time. Any statements regarding the following are forward-looking statements:

- future crude oil, natural gas or chemicals prices;
- future production levels;
- future cost recovery oil revenues and our share of production from our operations in Yemen;
- future capital expenditures and their allocation to exploration and development activities;
- future sources of funding for our capital program;
- future debt levels;
- future cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of reserves;
- expected finding and development costs;
- expected operating costs;
- future demand for chemicals products;
- future expenditures and future allowances relating to environmental matters; and
- dates by which certain areas will be developed or will come onstream.

We believe that the forward-looking statements made are reasonable based on information available to us on the date such statements were made. However, no assurance can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements.

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[1] Within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended.

## Item 8. Financial Statements and Supplementary Financial Information

## REPORT OF MANAGEMENT

To the Shareholders of Nexen Inc.:

We are responsible for the preparation and integrity of all the information contained in the accompanying consolidated financial statements. Fulfilling this responsibility requires the preparation and presentation of our consolidated financial statements in accordance with generally accepted accounting principles in Canada with a reconciliation to generally accepted accounting principles in the US. We have established disclosure controls and procedures, internal controls and corporate-wide policies to ensure that Nexen's consolidated financial position, results of operations and cash flows are presented fairly.

Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all the required regulatory disclosures.

To gather and control financial data, we have established accounting and reporting systems supported by internal controls and an internal audit program. We believe that the existing internal controls provide reasonable assurance that assets are safeguarded against loss from unauthorized use or disposition and that the records are reliable for preparing consolidated financial statements and other financial information. Financial information displayed in other sections of this report has been reviewed to ensure consistency with the consolidated financial statements.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization including a written ethics and integrity policy that applies to all employees including the chief executive officer, chief financial officer and chief accounting officer or controller.

Our Board of Directors approves the consolidated financial statements. Their financial statement related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (the Audit Committee) with assistance from the Reserves Review Committee regarding the annual review of our crude oil and natural gas reserves and from the Finance Committee regarding the assessment and mitigation of risk. The Audit Committee is composed entirely of independent directors, and includes three directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors, and external auditors, to discuss reporting and control issues and ensures each party is properly discharging its responsibilities. The Audit Committee also considers the independence of the external auditors and reviews their fees. The internal and external auditors have access to the Committee without the presence of management.

On June 3, 2002, the Canadian firm of Deloitte & Touche LLP (Deloitte Canada) completed a transaction with the Canadian firm of Arthur Andersen LLP (Andersen Canada) to integrate the partners and staff of Andersen Canada into Deloitte Canada. On July 11, 2002, Deloitte Canada, an independent firm of chartered accountants, was appointed by the Board to audit the consolidated financial statements, and to provide an independent professional opinion thereon.

(signed) "Charles W. Fischer"
President and Chief Executive Officer

(signed) "Marvin F. Romanow"
Executive Vice President,
and Chief Financial Officer

## REPORT OF INDEPENDENT AUDITORS

To the Shareholders of Nexen Inc.:

We have audited the consolidated balance sheet of Nexen Inc. as at December 31, 2002 and the consolidated statements of income, cash flows and shareholders' equity for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards in Canada and the United States of America. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Nexen Inc. as at December 31, 2002 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements of Nexen Inc. as at December 31, 2001 and for each of the two years in the period ended December 31, 2001 were audited by other auditors who have ceased operations. Those auditors expressed an opinion without reservation on those consolidated financial statements in their report dated January 23, 2002. As described in Note 1(r), certain amounts in these consolidated financial statements have been reclassified to give effect to a change in generally accepted accounting principles in 2002. We audited the reclassification of amounts described in Note 1(r) that relate to the 2001 and 2000 consolidated financial statements. In our opinion, such reclassification is appropriate and has been properly applied. However, we were not engaged to audit, review or apply any procedures to the 2001 and 2000 consolidated financial statements of Nexen Inc. other than with respect to such reclassification and, accordingly, we do not express an opinion or any other form of assurance on the 2001 and 2000 financial statements taken as a whole.

Calgary, Alberta
January 23, 2003

(signed) "Deloitte & Touche LLP"
Chartered Accountants

**THIS REPORT OF INDEPENDENT CHARTERED ACCOUNTANTS IS A COPY OF THE REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP AND HAS NOT BEEN REISSUED.**

## REPORT OF INDEPENDENT CHARTERED ACCOUNTANTS

To the Shareholders of Nexen Inc.:

We have audited the consolidated balance sheet of Nexen Inc. as at December 31, 2001 and 2000 and the consolidated statements of income, cash flows and shareholders' equity for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards in Canada and the United States. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001 in accordance with generally accepted accounting principles in Canada.

Calgary, Alberta
January 23, 2002

(signed) "Arthur Andersen LLP"
Chartered Accountants

## Nexen Inc.
## Consolidated Statement of Income
## For the Three Years Ended December 31, 2002

Cdn$ millions

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| **Revenues** | | | |
| Net Sales | 2,606 | 2,593 | 2,705 |
| Marketing and Other (Notes 1(r) and 12) | 504 | 475 | 220 |
| Gain (Loss) on Disposition of Assets | (8) | 5 | 42 |
| | 3,102 | 3,073 | 2,967 |
| **Expenses** | | | |
| Operating | 782 | 781 | 687 |
| Transportation and Other (Note 1(r)) | 469 | 400 | 182 |
| General and Administrative | 152 | 136 | 117 |
| Depreciation, Depletion and Amortization | 720 | 625 | 667 |
| Exploration | 189 | 265 | 173 |
| Interest (Note 7) | 109 | 112 | 132 |
| | 2,421 | 2,319 | 1,958 |
| **Income before Income Taxes** | 681 | 754 | 1,009 |
| **Provision for Income Taxes** (Note 13) | | | |
| Current | 223 | 216 | 242 |
| Future | 6 | 88 | 165 |
| | 229 | 304 | 407 |
| **Net Income** | 452 | 450 | 602 |
| **Dividends on Preferred Securities, Net of Income Taxes** (Note 8) | 43 | 39 | 37 |
| **Net Income Attributable to Common Shareholders** | 409 | 411 | 565 |
| **Earnings Per Common Share** ($/share) | | | |
| Basic (Note 9) | 3.34 | 3.40 | 4.52 |
| Diluted (Note 9) | 3.30 | 3.36 | 4.46 |

*See accompanying notes to Consolidated Financial Statements.*

**Nexen Inc.**
**Consolidated Balance Sheet**
**December 31, 2002 and 2001**
Cdn$ millions

| | 2002 | 2001 |
|---|---|---|
| **Assets** | | |
| **Current Assets** | | |
| Cash and Short-Term Investments | 59 | 61 |
| Accounts Receivable (Note 3) | 988 | 609 |
| Inventories and Supplies (Note 4) | 256 | 189 |
| Other | 26 | 20 |
| Total Current Assets | 1,329 | 879 |
| **Property, Plant and Equipment** (Note 5) | 4,863 | 4,170 |
| **Goodwill** (Note 1) | 36 | 36 |
| **Future Income Tax Assets** (Note 13) | 263 | 212 |
| **Deferred Charges and Other Assets** | 69 | 28 |
| | 6,560 | 5,325 |
| **Liabilities and Shareholders' Equity** | | |
| **Current Liabilities** | | |
| Short-Term Borrowings (Note 7) | 18 | 51 |
| Accounts Payable and Accrued Liabilities | 1,194 | 773 |
| Accrued Interest Payable | 39 | 22 |
| Dividends Payable | 9 | 9 |
| Total Current Liabilities | 1,260 | 855 |
| **Long-Term Debt** (Note 7) | 1,844 | 1,484 |
| **Future Income Tax Liabilities** (Note 13) | 873 | 869 |
| **Dismantlement and Site Restoration** | 191 | 182 |
| **Other Deferred Credits and Liabilities** | 44 | 31 |
| **Shareholders' Equity** (Note 8) | | |
| Preferred Securities | 724 | 724 |
| Common Shares, no par value | | |
| Authorized: Unlimited | | |
| Outstanding: 2002 - 122,965,830 shares | | |
| 2001 - 121,202,444 shares | 440 | 389 |
| Retained Earnings | 1,069 | 697 |
| Cumulative Foreign Currency Translation Adjustment | 115 | 94 |
| Total Shareholders' Equity | 2,348 | 1,904 |
| **Commitments and Contingencies** (Note 10) | | |
| | 6,560 | 5,325 |

*See accompanying notes to Consolidated Financial Statements.*

Approved on behalf of the Board:

(Signed) "Charles W. Fischer"
Director

(Signed) "David A. Hentschel"
Director

## Nexen Inc.
## Consolidated Statement of Cash Flows
## For the Three Years Ended December 31, 2002

Cdn$ millions

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| **Operating Activities** | | | |
| Net Income | 452 | 450 | 602 |
| Charges and Credits to Income not Involving Cash (Note 14) | 742 | 708 | 794 |
| Exploration Expense | 189 | 265 | 173 |
| Changes in Non-Cash Working Capital (Note 14) | (46) | 143 | (243) |
| Other | (15) | - | 3 |
| | 1,322 | 1,566 | 1,329 |
| **Financing Activities** | | | |
| Proceeds from Long-Term Debt | 882 | 315 | 2,467 |
| Repayment of Long-Term Debt | (511) | (400) | (2,284) |
| Proceeds from (Repayment of) Short-Term Borrowings, Net | (33) | (17) | 59 |
| Dividends on Preferred Securities | (72) | (70) | (68) |
| Dividends on Common Shares | (37) | (37) | (37) |
| Issue of Common Shares | 51 | 39 | 45 |
| Repurchase of Common Shares (Note 8) | - | - | (605) |
| Changes in Non-Cash Working Capital (Note 14) | - | - | (2) |
| Other | (23) | - | (2) |
| | 257 | (170) | (427) |
| **Investing Activities** | | | |
| Capital Expenditures | | | |
| Exploration and Development | (1,477) | (1,162) | (822) |
| Chemicals, Corporate and Other | (144) | (120) | (58) |
| Proved Property Acquisitions | (4) | (122) | (35) |
| Acquisition (Note 2) | - | - | (39) |
| Proceeds on Disposition of Assets | 49 | 5 | 42 |
| Changes in Non-Cash Working Capital (Note 14) | 7 | (18) | 42 |
| Other | - | (52) | (27) |
| | (1,569) | (1,469) | (897) |
| **Effect of Exchange Rate Changes on Cash and Short-Term Investments** | (12) | 24 | 12 |
| **Increase (Decrease) in Cash and Short-Term Investments** | (2) | (49) | 17 |
| **Cash and Short-Term Investments – Beginning of Year** | 61 | 110 | 93 |
| **Cash and Short-Term Investments – End of Year** | 59 | 61 | 110 |

*See accompanying notes to Consolidated Financial Statements.*

**Nexen Inc.**
**Consolidated Statement of Shareholders' Equity**
**For the Three Years Ended December 31, 2002**
Cdn$ millions

| | Preferred Securities (Note 8) | Common Shares (Note 8) | Contributed Surplus | Retained Earnings | Cumulative Foreign Currency Translation Adjustment |
|---|---|---|---|---|---|
| **December 31, 1999** | 724 | 358 | 14 | 666 | 36 |
| Exercise of Stock Options | - | 25 | - | - | - |
| Issue of Common Shares | - | 20 | - | - | - |
| Repurchase of Common Shares (Note 8) | - | (53) | (14) | (535) | - |
| Adoption of Liability Method of Accounting for Income Taxes (Note 13) | - | - | - | (336) | - |
| Net Income | - | - | - | 602 | - |
| Dividends on Preferred Securities, Net of Income Taxes | - | - | - | (37) | - |
| Dividends on Common Shares | - | - | - | (37) | - |
| Translation Adjustment, Net of Income Taxes | - | - | - | - | 27 |
| **December 31, 2000** | 724 | 350 | - | 323 | 63 |
| Exercise of Stock Options | - | 16 | - | - | - |
| Issue of Common Shares | - | 23 | - | - | - |
| Net Income | - | - | - | 450 | - |
| Dividends on Preferred Securities, Net of Income Taxes | - | - | - | (39) | - |
| Dividends on Common Shares | - | - | - | (37) | - |
| Translation Adjustment, Net of Income Taxes | - | - | - | - | 31 |
| **December 31, 2001** | 724 | 389 | - | 697 | 94 |
| Exercise of Stock Options | - | 27 | - | - | - |
| Issue of Common Shares | - | 24 | - | - | - |
| Net Income | - | - | - | 452 | - |
| Dividends on Preferred Securities, Net of Income Taxes | - | - | - | (43) | - |
| Dividends on Common Shares | - | - | - | (37) | - |
| Translation Adjustment, Net of Income Taxes | - | - | - | - | 21 |
| **December 31, 2002** | 724 | 440 | - | 1,069 | 115 |

*See accompanying notes to Consolidated Financial Statements.*

## 1. ACCOUNTING POLICIES

The Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and US GAAP on the Consolidated Financial Statements is disclosed in Note 16. Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and revenues and expenses during the reporting period. Actual results can differ from those estimates.

### (a) Principles of Consolidation

The Consolidated Financial Statements include the accounts of Nexen Inc. and our subsidiary companies and partnerships in which we have a controlling interest (Nexen, we or our). All subsidiary companies and, effective April 18, 2000 all partnerships, are wholly owned. All material intercompany accounts and transactions have been eliminated. Substantially all exploration, development and production activities related to our oil and gas business and the Syncrude Joint Venture (Syncrude) are conducted jointly with others and our accounts reflect only Nexen's proportionate interest.

### (b) Accounts Receivable

Accounts receivable are recorded based on our revenue recognition policy (see Note 1(i)). Our allowance for doubtful accounts provides for specific doubtful receivables.

### (c) Inventories and Supplies

Inventories and supplies for our oil and gas and chemicals segments are stated at the lower of cost or market value. Cost is determined on the first-in first-out method or average basis.

After October 25, 2002, inventories held by our marketing operation are accounted for at the lower of cost or market value determined on an average basis. Prior to that these inventories were accounted for on a mark-to-market basis. On October 25, 2002, generally accepted accounting principles followed by energy traders eliminated mark-to-market accounting for inventories (see Note 1(r)).

### (d) Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Improvements that increase capacity or extend the useful lives of the related assets are capitalized. Major maintenance or turnaround costs are expensed as incurred.

We follow successful efforts accounting for our oil and gas business. Under this method, we capitalize the costs of resource property acquisitions, exploratory drilling and all development. The cost of exploratory wells that are dry and all other exploration costs, including geological and geophysical costs and annual lease rentals, are charged to earnings.

We periodically evaluate our property, plant and equipment for impairment. If an adverse event or change indicates possible impairment, we estimate the undiscounted future cash flow for the related property. If the total undiscounted future cash flow is less than the carrying amount of the property, we calculate the fair value of the property using a discounted cash flow approach and write down the property to that amount. The cash flow estimates require assumptions about future commodity prices, operating costs and other factors. Actual results can differ from those estimates.

### (e) Depreciation, Depletion and Amortization (DD&A)

Under successful efforts accounting, oil and gas costs are depleted using the unit-of-production method. Development costs are depleted over remaining proved developed reserves and acquisition costs over proved reserves. Other plant and equipment costs are depreciated using the straight-line method based on the estimated useful lives of the assets, which range from 3 years to 30 years. Unproved property costs and major projects that are under construction or development are not depreciated, depleted or amortized.

### (f) Dismantlement and Site Restoration

We provide for dismantlement and site restoration costs on our resource properties, facilities, production platforms and pipelines and our chemicals facilities. We estimate the total future dismantlement and site restoration costs required to comply with current legislation and industry practices. We then provide for those costs annually based on proved reserves or estimated remaining asset lives. The annual provision is included in depreciation, depletion and amortization. Expenditures are charged against the provision as incurred.

### (g) Goodwill

On January 1, 2002, we adopted the new recommendations of the Canadian Institute of Chartered Accountants (CICA). Under the new standard, goodwill and intangible assets with an indefinite useful life are no longer amortized, but are tested for impairment at least annually based on estimated future cash flows. No goodwill impairment writedowns were required during the year. Our unamortized goodwill at January 1, 2002 was $36 million. The following shows the adjusted net income and earnings per common share had the new standard been applied in 2001 and 2000:

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Net Income Attributable to Common Shareholders | | | |
| As Reported | 409 | 411 | 565 |
| Add: Goodwill Amortization | - | 6 | 5 |
| Adjusted | 409 | 417 | 570 |
| | | | |
| Earnings Per Common Share ($/share) | | | |
| Basic as Reported | 3.34 | 3.40 | 4.52 |
| Adjusted | 3.34 | 3.46 | 4.56 |
| | | | |
| Diluted as Reported | 3.30 | 3.36 | 4.46 |
| Adjusted | 3.30 | 3.42 | 4.50 |

### (h) Carried Interest

According to our Masila Block agreement in Yemen (the Agreement), production generated from the Masila Block (the Project) is shared between the Government of Yemen (the Government), Nexen and the other Project participants. Production is divided into cost recovery oil and profit oil.

Cost recovery oil provides for the recovery of operating, exploration and development costs, based on a formula, and is limited to a maximum of 40% of production during each fiscal year. Nexen and the other participants fund the Government's share of exploration and development costs. Cost recovery oil received by us is recorded as revenue, and includes a carried interest component which allows us to recover the Government's share of exploration and development costs we have incurred. Costs not recovered in the year may be recovered in future years, and are included in property, plant and equipment. Recoveries of capitalized carried costs are shown as depreciation or depletion expense.

Profit oil is the production remaining after deducting cost recovery oil. Profit oil is shared by the Government and the Project participants on a sliding scale based on production rates, and is accounted for using successful efforts accounting. The Government's portion of profit oil includes an amount for Nexen's income taxes payable under the laws of Yemen.

### (i) Revenue Recognition

#### Crude Oil, Natural Gas and Chemicals

Revenue is recognized when title passes to the customer. When we produce or sell crude oil and natural gas above or below our working interest, production overlifts and underlifts occur. Overlifts are recorded as liabilities, and underlifts are recorded as assets. We settle these over time as liftings are equalized, or in cash when production ceases.

#### Marketing

Financial and physical commodity contracts (collectively derivative instruments) held by our marketing operation are marked-to-market. Under mark-to-market accounting, these contracts are recorded at fair value at the balance sheet date. We record the net gain or loss on these contracts in marketing and other. Prior to October 25, 2002 non-derivative instruments, including transportation contracts, were also marked-to-market. As of October 25, 2002, costs relating to these instruments are expensed as incurred. These costs are now recorded in transportation and other (see Note 1(r)).

### (j) Income Taxes

Effective January 1, 2000, we began following the liability method of accounting for income taxes (see Note 13). This method recognizes income tax assets and liabilities at enacted rates, based on differences between financial statement reporting and tax amounts. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income in the period that the change occurs.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, since we intend to invest such earnings indefinitely in foreign operations.

### (k) Petroleum Resource Rent Tax

Petroleum Resource Rent Tax with respect to our Australian oil and gas operations is accounted for on the liability basis with a future liability or asset recognized on temporary differences at the current enacted rate. Temporary differences mainly relate to depletion, dismantlement and site restoration. We treat the related cost as a royalty and deduct it from sales.

### (l) Foreign Currency Translation

Our foreign operations, which are considered financially and operationally independent, are translated from their functional currency into Canadian dollars as follows:

- assets and liabilities using exchange rates at the balance sheet dates; and
- revenues and expenses using the average exchange rates throughout the year.

Gains and losses resulting from this translation are included in the cumulative foreign currency translation adjustment in shareholders' equity.

Monetary balances denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from translation, except on our US-dollar debt, are included in income. We have designated our US-dollar debt as a hedge against our net investment in US-dollar based self-sustaining foreign operations. Gains and losses resulting from the translation of the US-dollar debt, to the extent they do not exceed our investment in foreign operations, are included in the cumulative foreign currency translation adjustment in shareholders' equity.

### (m) Capitalized Interest

We capitalize interest on qualifying assets until they are put into service, using the weighted-average interest rate on all our borrowings.

### (n) Derivative Instruments

**Non-Trading Activities**

We use derivative instruments for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates, as described in Note 6. Hedge accounting is used when there is a high degree of correlation between price movements in the derivative instrument and the item designated as being hedged. We recognize gains and losses in the same period as the hedged item. If correlation ceases, hedge accounting is terminated and future changes in the market value of the derivative instruments are recognized as gains or losses in the period of change.

**Trading Activities**

Our marketing operation uses derivative instruments for marketing and trading crude oil and natural gas. Derivative instruments used include:

- exchange-traded futures and options;
- non-exchange traded forwards, swaps and options; and
- commodity contracts settled with physical delivery.

We account for these instruments using mark-to-market accounting, and record the net gain or loss in marketing and other. The fair value of these instruments is recorded as accounts receivable or payable. They are classified as long term or short term based on their anticipated settlement date.

### (o) Employee Benefits

The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and management's best estimate of the plans' investment performance, salary escalations and retirement ages of employees. To calculate the plans' expected returns, assets are measured at fair value. Past service costs arising from plan amendments, and net actuarial gains and losses which exceed 10% of the greater of the benefit obligation and the fair value of plan assets, are amortized on a straight-line basis over the expected average remaining service life of the employee group.

### (p) Stock-Based Compensation

We use the intrinsic value based method of accounting for stock options. Under this method, no compensation expense has been recognized for stock options granted to employees and directors. On January 1, 2002, we adopted the new CICA recommendations. The new standard requires companies that do not recognize the compensation expense determined under the fair-value based method to make pro forma disclosures of net income and earnings per common share as if that method of accounting had been applied (see Note 8).

We provide stock appreciation rights to employees as described in Note 8. Obligations are accrued as compensation expense over the vesting period of the stock appreciation rights.

### (q) Cash and Short-Term Investments

Cash and short-term investments are instruments that mature within three months of their purchase.

### (r) Changes in Accounting Policies – Marketing Activities

**Mark-to-Market**

On October 25, 2002, regulators changed accounting principles, eliminating mark-to-market accounting for our marketing inventories and our non-derivative energy contracts. Under the new principles:

- we measure marketing inventories at the lower of cost or market; and
- we record non-derivative energy contracts, including our transportation and storage capacity contracts, at cost as incurred.

We recorded the change to inventory prospectively as the effects on previous periods cannot be determined. Inventories at October 25, 2002 have been attributed a cost based on their market value on that date. Inventories purchased after October 25, 2002 are recorded at cost. We removed the mark-to-market on our transportation contracts from earnings retroactively to the beginning of the year. The impact on previous years is immaterial. Under the previous method, our results would have been:

| | 2002 |
|---|---|
| Net Income Attributable to Common Shareholders | |
| As Reported | 409 |
| Mark-to-Market on inventory and transportation, net of income taxes | 4 |
| Adjusted | 413 |
| Earnings per Common Share ($/share) | |
| Basic as Reported | 3.34 |
| Adjusted | 3.37 |
| Diluted as Reported | 3.30 |
| Adjusted | 3.34 |

**Presentation of Transportation**

During the year, we adopted the new interpretation of the Emerging Issues Committee relating to the presentation of costs for which we are reimbursed. We pay for the transportation of the crude oil, natural gas and chemicals products that we market, and then bill our customers for the transportation. Under the new interpretation, this transportation should be presented as a cost to us. Previously, we netted this cost against our revenue. Effective October 1, 2002, we show these costs as transportation and other on the consolidated statement of income, resulting in the following increases:

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Net Sales | 35 | 32 | 31 |
| Marketing and Other | 423 | 342 | 131 |
| Transportation and Other | 458 | 374 | 162 |

## 2. ACQUISITION

Effective July 31, 2000, our marketing business acquired Northridge Energy Marketing Ltd. for cash consideration of $39 million. We used the purchase method to account for the acquisition and included the results in our financial statements from the acquisition date. The purchase consisted of the following:

| | |
|---|---|
| Current Assets | 172 |
| Current Liabilities | (155) |
| Goodwill | 13 |
| Property, Plant and Equipment | 9 |
| | 39 |

## 3. ACCOUNTS RECEIVABLE

| | 2002 | 2001 |
|---|---|---|
| Trade | | |
| Oil and Gas | | |
| Marketing | 574 | 305 |
| Other | 330 | 220 |
| Chemicals and Other | 59 | 57 |
| | 963 | 582 |
| Non-Trade | 34 | 36 |
| | 997 | 618 |
| Allowance for Doubtful Accounts | (9) | (9) |
| | 988 | 609 |

## 4. INVENTORIES AND SUPPLIES

| | 2002 | 2001 |
|---|---|---|
| Finished Products | | |
| Oil and Gas | | |
| Marketing | 130 | 56 |
| Other | - | 15 |
| Chemicals and Other | 13 | 15 |
| | 143 | 86 |
| Work in Process | 6 | 6 |
| Field Supplies | 107 | 97 |
| | 256 | 189 |

## 5. PROPERTY, PLANT AND EQUIPMENT

| | 2002 | | | 2001 | | |
|---|---|---|---|---|---|---|
| | Cost | Accumulated DD&A | Net Book Value | Cost | Accumulated DD&A | Net Book Value |
| Oil and Gas | | | | | | |
| Yemen | 2,054 | 1,646 | 408 | 1,839 | 1,491 | 348 |
| Canada | 3,098 | 1,137 | 1,961 | 2,867 | 913 | 1,954 |
| United States | 2,186 | 959 | 1,227 | 1,636 | 848 | 788 |
| Australia | 209 | 184 | 25 | 167 | 144 | 23 |
| Other Countries | 305 | 198 | 107 | 271 | 166 | 105 |
| Marketing | 86 | 40 | 46 | 89 | 32 | 57 |
| | 7,938 | 4,164 | 3,774 | 6,869 | 3,594 | 3,275 |
| Syncrude | 628 | 139 | 489 | 487 | 127 | 360 |
| Chemicals | 789 | 345 | 444 | 744 | 296 | 448 |
| Corporate and Other | 213 | 57 | 156 | 137 | 50 | 87 |
| | 9,568 | 4,705 | 4,863 | 8,237 | 4,067 | 4,170 |

The above table includes capitalized costs of $585 million (2001 - $251 million) relating to unproved properties and projects under construction or development. These costs are not being depreciated, depleted or amortized.

## 6. DERIVATIVE INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The nature of our operations and long-term debt expose us to fluctuations in commodity prices, foreign-currency exchange rates, interest rates and credit risk. We recognize these risks and manage our operations to minimize our exposure to the extent practical and, to a lesser extent, using derivative instruments. Our marketing operation uses derivative instruments to manage its exposure to commodity price fluctuations and for trading purposes. We use exchange-traded futures and options and non-exchange traded forwards, swaps and options, which may be settled in cash or by delivery of the physical commodity. The Finance Committee of the Board of Directors and our Risk Management Committee monitor our exposure to the above risks and regularly review our derivative activities and all outstanding positions.

### (a) Commodity price risk management

**Non-Trading Activities**

We generally sell our crude oil and natural gas under short-term market based contracts. During 2001 and 2000, we purchased put options to establish a minimum price for our crude oil to mitigate the impact of any price declines. This minimum price per barrel equaled the contract strike price for all hedged volumes if the West Texas Intermediate crude oil price (WTI) averaged less than the strike price for the contract period. In 2001, we paid a US $13 million premium for the put options. The contracts expired unexercised in 2002, as WTI did not average less than the strike price during the contract period.

During 2002 and 2001, we purchased fixed-to-floating swaps to modify the terms of certain fixed-price natural gas contracts as we prefer to receive an index-based price for our natural gas. Under the terms of these contracts, we must deliver 4 million cubic feet per day of natural gas to counterparties at prices ranging from $3.06 to $6.08 per thousand cubic feet. On settlement, we either pay or receive cash for the difference between the contract and floating rates. These swaps expire in 2003.

**Trading Activities**

Our marketing operation engages in crude oil and natural gas marketing activities to enhance prices from the sale of our own oil and gas production, and for energy trading. We enter into contracts to purchase and sell crude oil and natural gas. These contracts expose us to commodity price risk between the time contracted volumes are purchased and sold. We actively manage this risk by using energy-related futures, forwards, swaps and options, and by balancing physical and financial contracts in terms of volumes, timing of performance and delivery obligations. However, net open positions may exist, or we may establish them to take advantage of market conditions.

Open positions enable our marketing operation to generate income based on competitive information from marketing activities, but also expose us to risks of loss from fluctuating market prices. Our exposure is restricted to prescribed limits and is monitored daily using value-at-risk, stress testing and scenario analysis. The value-at-risk calculation estimates the maximum probable loss, given a 95% confidence level, that we would incur if our open positions were unwound over two days. Our net margin from trading activities is as follows:

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Net Revenue | 496 | 438 | 179 |
| Less: Transportation | 423 | 342 | 131 |
| | 73 | 96 | 48 |
| Value-at-Risk | | | |
| Year End | 19 | 19 | 13 |
| Average | 17 | 13 | 4 |

### (b) Foreign currency exchange rate risk management

A substantial portion of our activities are transacted in or referenced to US dollars. These activities include:

- prices received for sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses related to our oil and gas and chemicals operations outside Canada; and
- short-term and long-term borrowings.

We manage our exposure to fluctuations between the US and Canadian dollars by minimizing the need to convert between the two currencies. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. Our US-dollar debt has been designated as a hedge against our net investment in foreign operations. The foreign exchange gains or losses realized on this debt are included in the cumulative foreign currency translation adjustment in shareholders' equity. Our net investment in foreign operations and our US-dollar long-term debt at December 31 are as follows:

| (US$ millions) | 2002 | 2001 |
|---|---|---|
| Net Investment in Foreign Operations | 1,389 | 887 |
| Long-Term Debt | 962 | 728 |

We do not have any material exposure to highly inflationary foreign currencies.

We occasionally use derivative instruments to effectively convert cash flows from Canadian to US dollars and vice versa. At December 31, 2002, we held a foreign currency derivative instrument that obligates us and the counterparty to exchange principal and interest amounts. In November 2006, we will pay US $37 million and receive Cdn $50 million (see Note 7).

### (c) Interest rate risk management

We use fixed and floating rate debt to finance our operations. The floating rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating rate borrowings. At December 31, 2002, fixed-rate borrowings comprised 100% (2001 – 69%) of our long-term debt at an effective average rate of 7.4% (2001 - 7.0%). During the year we periodically drew on our unsecured syndicated term credit facilities. We had no interest rate swaps outstanding in 2002 or 2001.

### (d) Credit risk management

A substantial portion of our accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international customers. We are also exposed to possible non-performance by derivative instrument counterparties. We assess the financial strength of our customer and counterparty base, including those involved in marketing and other commodity arrangements and we limit the total exposure to individual counterparties. As well, a number of our contracts contain provisions that allow us to demand the posting of collateral in the event downgrades to non-investment grade occur. Credit risk, including credit concentrations are routinely reported to our Risk Management Committee. We also use standard agreements that net positive and negative exposures of a single counterparty. We believe this minimizes our overall credit risk.

### (e) Carrying value and estimated fair value of derivative instruments

| Assets/(Liabilities) | 2002 | | | 2001 | | |
|---|---|---|---|---|---|---|
| | Carrying Value | Fair Value | Unrealized Gain/(Loss) | Carrying Value | Fair Value | Unrealized Gain/(Loss) |
| Long-Term Debt | (1,844) | (1,948) | (104) | (1,484) | (1,465) | 19 |
| Currency Swap | - | (3) | (3) | - | - | - |
| Preferred Securities | (724) | (756) | (32) | (724) | (769) | (45) |
| Crude Oil Put Options | - | - | - | 2 | - | (2) |
| Natural Gas Swaps | - | 2 | 2 | - | (7) | (7) |

The estimated fair value of all derivative instruments is based on quoted market prices and if not available, on estimates from third-party brokers or dealers or amounts derived from valuation models. The carrying value of cash and short-term investments, amounts receivable and short-term obligations approximates their fair value because the instruments are near maturity. Amounts receivable and payable by our marketing operations related to derivative instruments are equal to fair value as we use the mark-to-market method to value them. Amounts related to derivative instruments included in deferred charges and other assets and other deferred credits and liabilities are $14 million and $7 million, respectively. These derivative instruments are held by our marketing operation and settle beyond 2003.

## 7. LONG-TERM DEBT AND SHORT-TERM BORROWINGS

| | 2002 | 2001 |
|---|---|---|
| Unsecured Syndicated Term Credit Facilities (a) | - | 424 |
| Unsecured Redeemable Notes, due 2004 (b) | 355 | 358 |
| Unsecured Redeemable Debentures, due 2006 (c) | 108 | 109 |
| Unsecured Redeemable Medium Term Notes, due 2007 (d) | 150 | 150 |
| Unsecured Redeemable Medium Term Notes, due 2008 (e) | 125 | 125 |
| Unsecured Redeemable Notes, due 2028 (f) | 316 | 318 |
| Unsecured Redeemable Notes, due 2032 (g) | 790 | - |
| | 1,844 | 1,484 |

### (a) Unsecured syndicated term credit facilities

Nexen has committed unsecured revolving term credit facilities totalling $1,576 million available for 5 years, and each lender has the option to extend them on an annual basis. No repayments are required until the end of the availability period. Borrowings are available in the form of Canadian bankers' acceptances, LIBOR-based loans, Canadian prime loans or US-dollar base rate loans. Interest is payable monthly at a floating rate. During 2002, the weighted average interest rate was 2.5% (2001 – 6.0%).

### (b) Unsecured redeemable notes, due 2004

During February 1999, we issued US $225 million of notes. Interest is payable semi-annually at a rate of 7.125%, and the principal is to be repaid in February 2004. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes.

### (c) Unsecured redeemable debentures, due 2006

During November 1996, we issued $100 million of unsecured 10-year redeemable debentures. Interest is payable semi-annually at a rate of 6.85% and the principal is to be repaid in November 2006. In December 1996, $50 million of this obligation was effectively converted through a currency exchange contract with a Canadian chartered bank to a US $37 million liability bearing interest at 6.75% for the term of the debentures. We may redeem part or all of the debentures at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the debentures plus 0.1%.

### (d) Unsecured redeemable medium term notes, due 2007

During July 1997, we issued $150 million of notes. Interest is payable semi-annually at a rate of 6.45% and the principal is to be repaid in July 2007. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the notes plus 0.125%.

### (e) Unsecured redeemable medium term notes, due 2008

During October 1997, we issued $125 million of notes. Interest is payable semi-annually at a rate of 6.3% and the principal is to be repaid in June 2008. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the notes plus 0.125%.

### (f) Unsecured redeemable notes, due 2028

During April 1998, we issued US $200 million of notes. Interest is payable semi-annually at a rate of 7.4% and the principal is to be repaid in May 2028. We may redeem part or all of the notes any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.25%.

### (g) Unsecured redeemable notes, due 2032

During March 2002, we issued US $500 million of notes. Interest is payable semi-annually at a rate of 7.875% and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.375%. Included in deferred charges and other assets is a debt discount of US $14 million.

### (h) Debt repayments

| | |
|---|---|
| 2003 | - |
| 2004 | 355 |
| 2005 | - |
| 2006 | 108 |
| 2007 | 150 |
| Thereafter | 1,231 |
| | 1,844 |

### (i) Debt covenants

The majority of our debt instruments contain covenants regarding certain financial ratios and our ability to grant security. At December 31, 2002, we were in compliance with all covenants.

### (j) Short-term borrowings

Nexen has unsecured operating loan facilities of approximately $301 million. Interest is payable at floating rates and the facilities are subject to periodic reviews. During 2002, the weighted average interest rate on short-term borrowings was 2.3% (2001 - 5.5%).

Occasionally we sell the future proceeds of our accounts receivable; however, we retain a 10% exposure to related credit losses. At December 31, 2002, we sold $178 million (2001 - $100 million) of accounts receivable. The retained credit exposure of $18 million (2001 - $10 million) is included in short-term borrowings.

### (k) Interest expense

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Long-Term Debt | 134 | 106 | 125 |
| Other | 6 | 6 | 7 |
| Total | 140 | 112 | 132 |
| Less: Capitalized | 31 | - | - |
| | 109 | 112 | 132 |

Capitalized interest relates to and is included as part of the cost of oil and gas properties. The capitalization rates are based on our weighted-average cost of borrowings.

## 8. SHAREHOLDERS' EQUITY

### (a) Preferred Securities

| | Principal Amount | Interest Rate | Maturity Date | Call Date |
|---|---|---|---|---|
| | (US$ millions) | (%) | | |
| Preferred Securities | 259 | 9.75 | October 30, 2047 | October 30, 2003 |
| Preferred Securities | 217 | 9.375 | March 31, 2048 | February 9, 2004 |

Nexen may redeem part or all of the preferred securities on or after their redemption or call date. We may defer, subject to certain conditions, up to 20 consecutive quarterly interest payments and may satisfy our interest, principal or redemption payments by issuing common shares. Interest is payable quarterly.

Since we have the unrestricted ability to settle the interest, principal and redemption payments by issuing common shares, the preferred securities are classified as equity. We record the principal amount in shareholders' equity and interest payments, net of income taxes, are classified as dividends and charged directly to retained earnings.

### (b) Authorized Capital

Authorized share capital consists of an unlimited number of common shares of no par value, and an unlimited number of Class A preferred shares of no par value, issuable in series.

### (c) Issued common shares and dividends

| (thousands of shares) | 2002 | 2001 | 2000 |
|---|---|---|---|
| Beginning of Year | 121,202 | 119,855 | 138,145 |
| Issue of Common Shares for Cash: | | | |
| Exercise of Stock Options | 1,090 | 648 | 1,129 |
| Dividend Reinvestment Plan | 500 | 533 | 433 |
| Employee Flow-through Shares | 174 | 166 | 148 |
| Repurchase of Common Shares | - | - | (20,000) |
| End of Year | 122,966 | 121,202 | 119,855 |
| | | | |
| Dividends per Common Share ($/share) | 0.30 | 0.30 | 0.30 |
| | | | |
| Cash Consideration (Cdn$ millions) | | | |
| Exercise of Stock Options | 27 | 16 | 25 |
| Dividend Reinvestment Plan | 17 | 17 | 14 |
| Employee Flow-through Shares | 7 | 6 | 6 |
| | 51 | 39 | 45 |

At December 31, 2002, there were 1,783,968 (2001 – 489,329; 2000 – 1,022,545) common shares reserved for issuance under the Dividend Reinvestment Plan.

In March 2000, Nexen, Ontario Teachers' Pension Plan Board (Teachers) and Occidental Petroleum Corporation (Occidental) entered into an agreement where Occidental would sell its 29% interest in Nexen. The agreement was approved by a majority of Nexen shareholders other than Occidental and Teachers at a meeting of shareholders on April 17, 2000. Under the agreement, Teachers purchased 20.2 million of Nexen's common shares. Nexen repurchased 20 million common shares for $605 million, including associated fees. When repurchased, the common shares were cancelled.

## (d) Stock Options Granted, Exercised and Forfeited

We have granted options to purchase common shares to directors, officers and employees. Each option permits the holder to purchase one common share of Nexen at the stated exercise price. Options granted prior to February 2001 vest over 4 years and are exercisable on a cumulative basis over 10 years. Options granted after February 2001 vest over 3 years and are exercisable on a cumulative basis over 5 years. At the time of grant, the exercise price is equal to the market price. The following options have been granted:

| | Options | Weighted-Average Exercise Price |
|---|---|---|
| | (thousands) | ($/option) |
| **December 31, 1999** | 6,206 | 24 |
| Granted | 3,016 | 36 |
| Exercised | (1,129) | 22 |
| Forfeited | (117) | 25 |
| **December 31, 2000** | 7,976 | 29 |
| Granted | 1,645 | 31 |
| Exercised | (648) | 24 |
| Forfeited | (142) | 30 |
| **December 31, 2001** | 8,831 | 30 |
| Granted | 1,788 | 31 |
| Exercised | (1,090) | 25 |
| Forfeited | (53) | 30 |
| **December 31, 2002** | 9,476 | 30 |
| | | |
| **Options exercisable at December 31** | | |
| 2000 | 2,741 | 24 |
| 2001 | 4,232 | 27 |
| 2002 | 5,113 | 29 |

Common shares reserved for issuance under the stock option plan were 9,759,545 at December 31, 2002 (2001 - 10,896,060; 2000 – 8,044,680).

## (e) Exercise Price Range

| | Outstanding Options | | | Exercisable Options | |
|---|---|---|---|---|---|
| | Number of Options | Weighted-Average Exercise Price | Weighted-Average Years to Expiry | Number of Options | Weighted-Average Exercise Price |
| | (thousands) | ($/option) | (years) | (thousands) | ($/option) |
| $12.13 to $19.99 | 823 | 18 | 5 | 820 | 18 |
| $20.00 to $24.99 | 272 | 23 | 4 | 272 | 23 |
| $25.00 to $29.99 | 2,126 | 28 | 6 | 1,787 | 28 |
| $30.00 to $34.99 | 3,474 | 33 | 4 | 624 | 31 |
| $35.00 to $40.35 | 2,781 | 36 | 8 | 1,610 | 36 |
| | 9,476 | | | 5,113 | |

## (f) Estimated Fair-Value of Stock Options

We determine the estimated fair value of stock options issued using the Generalized Black-Scholes model under the following assumptions:

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Weighted-Average Fair Value ($/option) | 9.08 | 12.24 | 13.06 |
| | | | |
| Risk-Free Interest Rate (%) | 3.6 | 5.1 | 5.8 |
| Estimated Hold Period Prior to Exercise (years) | 3 | 5 | 5 |
| Volatility in the Price of Nexen's Common Shares (%) | 35 | 40 | 34 |
| Dividends per Common Share ($/share) | 0.30 | 0.30 | 0.30 |

### (g) Pro Forma Net Income – Fair-Value Based Method of Accounting for Stock Options

The following shows pro forma net income and earnings per common share had we applied the fair-value based method of accounting to all stock options outstanding.

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Net Income Attributable to Common Shareholders | | | |
| As Reported | 409 | 411 | 565 |
| Less: Fair Value of Stock Options | 22 | 25 | 14 |
| Pro Forma | 387 | 386 | 551 |
| Earnings Per Common Share ($/share) | | | |
| Basic as Reported | 3.34 | 3.40 | 4.52 |
| Pro Forma | 3.16 | 3.20 | 4.41 |
| Diluted as Reported | 3.30 | 3.36 | 4.46 |
| Pro Forma | 3.13 | 3.16 | 4.35 |

### (h) Stock Appreciation Rights

We established a stock appreciation rights plan in 2001. Under this plan, employees are entitled to cash payments equal to the excess of the market price of the common shares over the exercise price of the right. The vesting period and other terms of the plan are similar to the stock option plan. The total rights granted and outstanding at any time cannot exceed 10% of Nexen's total outstanding common shares.

| (millions of rights) | 2002 | 2001 |
|---|---|---|
| Rights Granted | 0.9 | 0.9 |
| Rights Outstanding | 1.8 | 0.9 |
| Weighted Average Exercise Price ($/right) | 33.94 | 31.17 |
| Rights Expensed ($ millions) | 2 | - |

## 9. EARNINGS PER COMMON SHARE

We calculate earnings per common share using Net Income Attributable to Common Shareholders and the weighted average number of common shares outstanding. We calculate diluted earnings per common share using Net Income Attributable to Common Shareholders and the weighted-average number of diluted common shares outstanding.

| (millions of shares) | 2002 | 2001 | 2000 |
|---|---|---|---|
| Weighted-average number of common shares outstanding | 122.4 | 120.7 | 125.0 |
| Shares issuable pursuant to stock options | 8.1 | 4.7 | 5.5 |
| Shares to be purchased from proceeds of stock options | (6.7) | (3.3) | (3.7) |
| Weighted-average number of diluted common shares outstanding | 123.8 | 122.1 | 126.8 |

In calculating diluted earnings per common share for the year ended December 31, 2002, we excluded 46,167 options (2001 - 2,992,903; 2000 - 42,000), because the exercise price was greater than the average market price of our common shares in those periods. During these three years, outstanding stock options were the only dilutive instrument.

## 10. COMMITMENTS AND CONTINGENCIES

| | 2003 | 2004 | 2005 | 2006 | 2007 | Thereafter |
|---|---|---|---|---|---|---|
| Operating leases | 50 | 39 | 34 | 18 | 16 | 100 |
| Transportation commitments | 180 | 40 | 32 | 32 | 31 | 113 |
| | 230 | 79 | 66 | 50 | 47 | 213 |

In November 2000, we committed to enter into a lease agreement when construction of a natural-gas-fired generating facility in Alberta was completed. On June 28, 2002, we exercised our option to buy out the lease for $67 million, which was the cost of construction plus interest on advances during the construction phase. We included this amount in capital expenditures for the year ended December 31, 2002.

There are a number of lawsuits and claims pending including income tax reassessments as described in Note 13, the ultimate results of which cannot be ascertained at this time. We record costs as they are incurred or become determinable. Management believes the resolution of these matters would not have a material adverse effect upon our consolidated financial position or results of operations.

## 11. PENSION AND OTHER POST RETIREMENT BENEFITS

Nexen has contributory and non-contributory defined benefit and defined contribution pension plans, which together cover substantially all employees. Syncrude has a defined benefit plan for its employees, and all of the Syncrude information in this note is Nexen's proportionate interest. Under these plans, we provide benefits to retirees based on their length of service and final average earnings.

### (a) Defined Benefit Pension Plans

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund this plan according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds.

| | 2002 | | 2001 | |
|---|---|---|---|---|
| Change in Benefit Obligation | Nexen | Syncrude | Nexen | Syncrude |
| Beginning of Year | 163 | 63 | 131 | 54 |
| Service Cost | 7 | 3 | 5 | 2 |
| Interest Cost | 10 | 4 | 9 | 4 |
| Plan Participants' Contributions | 2 | - | 2 | - |
| Actuarial Loss/(Gain) | (11) | - | 18 | 5 |
| Benefits Paid | (7) | (2) | (6) | (2) |
| Plan Amendment | - | - | 4 | - |
| End of Year | 164 | 68 | 163 | 63 |
| | | | | |
| Change in Fair Value of Plan Assets | | | | |
| Beginning of Year | 136 | 41 | 148 | 43 |
| Actual Return on Plan Assets | (7) | (3) | (12) | (2) |
| Employer's Contribution | 3 | 1 | 4 | 2 |
| Plan Participants' Contributions | 2 | - | 2 | - |
| Benefits Paid | (7) | (2) | (6) | (2) |
| End of Year | 127 | 37 | 136 | 41 |
| | | | | |
| Reconciliation of Funded Status | | | | |
| Funded Status [1] | (37) | (31) | (27) | (22) |
| Unamortized Transitional Obligation | 1 | - | 2 | - |
| Unamortized Prior Service Costs | 6 | 1 | 6 | 1 |
| Unamortized Net Actuarial Loss | 19 | 23 | 13 | 17 |
| Pension Liability | (11) | (7) | (6) | (4) |
| | | | | |
| Assumptions (%) | | | | |
| Discount Rate | 6.75 | 6.50 | 6.25 | 6.50 |
| Long-Term Rate of Employee Compensation Increase | 4.00 | 4.00 | 4.00 | 4.00 |
| Long-Term Annual Rate of Return on Plan Assets | 7.00 | 9.00 | 7.00 | 9.00 |

Note:

1 Included in the above amounts are unfunded obligations for supplemental benefits to the extent that the benefit under the defined benefit pension plan is limited by statutory guidelines. At December 31, 2002, the projected benefit obligation for supplemental benefits was $26 million (2001 - $25 million).

**Net Pension Expense Under Our Defined Benefit Pension Plans**

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Nexen | | | |
| Cost of Benefits Earned by Employees | 7 | 5 | 5 |
| Interest Cost on Benefits Earned | 10 | 9 | 9 |
| Expected Return on Plan Assets | (10) | (10) | (9) |
| Net Amortization and Deferral | 1 | - | - |
| Net | 8 | 4 | 5 |
| Syncrude | | | |
| Cost of Benefits Earned by Employees | 3 | 2 | 2 |
| Interest Cost on Benefits Earned | 4 | 4 | 3 |
| Expected Return on Pension Plan Assets | (4) | (4) | (4) |
| Net Amortization and Deferral | 1 | - | - |
| Net | 4 | 2 | 1 |
| Total | 12 | 6 | 6 |

### (b) Defined Contribution Pension Plans

Under these plans, pension benefits are based on plan contributions. During 2002, Canadian pension expense for these plans was $3 million (2001 - $3 million; 2000 - $2 million). During 2002, US pension expense for these plans was $3 million (2001 – $3 million; 2000 - $2 million).

### (c) Post-Retirement Benefits

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependents. These costs are fully accrued as compensation in the period employees work; however, these future obligations are not funded.

## 12. MARKETING AND OTHER

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Marketing Net Revenue (including Transportation) | 496 | 438 | 179 |
| Interest | 7 | 17 | 21 |
| Foreign Exchange Gains (Losses) | (3) | - | 3 |
| Other | 4 | 20 | 17 |
| | 504 | 475 | 220 |

## 13. INCOME TAXES

### (a) Change in Accounting Policy

Effective January 1, 2000, we adopted the CICA's new recommendations on accounting for income taxes and applied it retroactively without restating prior periods. The new recommendations use the liability method. The change in accounting policy increased (decreased) the following items on the Consolidated Financial Statements as at January 1, 2000:

| | |
|---|---|
| Future Income Tax Assets | 450 |
| Future Income Tax Liabilities | 786 |
| Retained Earnings | (336) |

Retained earnings decreased because of the future income tax cost of the Wascana Energy Inc. (Wascana) acquisition in 1997, in which the acquired tax basis was less than the purchase price.

### (b) Temporary Differences

| | 2002 | | 2001 | |
|---|---|---|---|---|
| | Future Income Tax Assets | Future Income Tax Liabilities | Future Income Tax Assets | Future Income Tax Liabilities |
| Property, Plant and Equipment, Net | 23 | 704 | 111 | 721 |
| Tax Losses Carried Forward | 226 | - | 34 | - |
| Deferred Income | - | 177 | - | 139 |
| Foreign Exchange | - | - | 1 | 3 |
| Recoverable Taxes | 14 | - | 101 | - |
| Other | - | (8) | 9 | 6 |
| | 263 | 873 | 256 | 869 |
| Valuation Allowance [1] | - | - | (44) | - |
| | 263 | 873 | 212 | 869 |

Note:
[1] The future income tax asset valuation allowance related to foreign tax credits being carried forward.

### (c) Canadian and Foreign Income Taxes

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Income before Income Taxes | | | |
| Canadian | 140 | 225 | 240 |
| Foreign | 541 | 529 | 769 |
| | 681 | 754 | 1,009 |
| Provision for Income Taxes | | | |
| Current | | | |
| Canadian | 4 | 6 | 7 |
| Foreign | 219 | 210 | 235 |
| | 223 | 216 | 242 |
| Future | | | |
| Canadian | 38 | 81 | 119 |
| Foreign | (32) | 7 | 46 |
| | 6 | 88 | 165 |

The Canadian and foreign components of the provision for income taxes are based on the jurisdiction in which income is taxed. Foreign taxes relate mainly to Yemen, the United States and Australia, and included Yemen cash taxes of $207 million (2001 - $191 million; 2000 - $217 million).

### (d) Reconciliation of Effective Tax Rate to the Canadian Federal Tax Rate

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Income before Income Taxes | 681 | 754 | 1,009 |
| Provision for Income Taxes Computed at the Canadian Statutory Rate | 269 | 317 | 449 |
| Add (Deduct) the Tax Effect of: | | | |
| Royalties and Rentals to Provincial Governments | 57 | 66 | 79 |
| Resource Allowance and Provincial Tax Rebates | (67) | (68) | (81) |
| Lower Tax Rates on Foreign Operations | (37) | (15) | (45) |
| Additional Canadian Tax on Canadian Resource Income | 8 | 2 | - |
| Federal and Provincial Capital Tax | 4 | 5 | 6 |
| Other | (5) | (3) | (1) |
| Provision for Income Taxes | 229 | 304 | 407 |

During 2002 and 2001, the federal and some provincial governments in Canada reduced statutory income tax rates. This reduced our liability and provision for future income taxes by $1 million (2001 - $5 million). The federal rate reduction does not apply to our earnings from Canadian resource properties.

### (e) Available Unused Tax Losses and Tax Contingencies

At December 31, 2002, we had unused tax losses totalling $534 million (2001 - $71 million) of which the majority relate to our US operations.

Nexen's income tax filings are subject to audit by taxation authorities. There are audits in progress and items under review, some that may increase our tax liability. In addition, we have filed Notices of Objection with respect to certain issues. While the results of these items cannot be ascertained at this time, management believes there is adequate provision for income taxes based on available information.

At the time of acquisition, Wascana had outstanding taxation issues in dispute from prior taxation years. Wascana disagreed with issues raised and has filed Notices of Objection. The value of the tax pools acquired at the time of acquisition reflected management's evaluation of the potential impact of these issues.

## 14. CASH FLOWS

### (a) Charges and credits to income not involving cash

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Depreciation, Depletion and Amortization | 720 | 625 | 667 |
| Loss (Gain) on Disposition of Assets | 8 | (5) | (42) |
| Future Income Taxes | 6 | 88 | 165 |
| Other | 8 | - | 4 |
| | 742 | 708 | 794 |

### (b) Changes in non-cash working capital

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Operating Activities | | | |
| Accounts Receivable | (388) | 471 | (521) |
| Inventories and Supplies | (73) | 73 | (120) |
| Other Current Assets | (6) | (5) | 3 |
| Accounts Payable and Accrued Liabilities | 407 | (399) | 390 |
| Accrued Interest Payable | 17 | 1 | (1) |
| Dividends Payable | - | - | (1) |
| Effect of Foreign Exchange Rate Changes on Non-Cash Working Capital | (3) | 2 | 7 |
| | (46) | 143 | (243) |
| Financing Activities | | | |
| Accounts Payable and Accrued Liabilities | - | - | (2) |
| Investing Activities | | | |
| Accounts Payable and Accrued Liabilities | 7 | (18) | 42 |
| Total | (39) | 125 | (203) |

### (c) Other cash flow information

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Interest Paid | 117 | 106 | 133 |
| Income Taxes Paid | 238 | 211 | 236 |

## 15. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen has three operating segments in various industries and geographic locations:

**Oil and Gas:** We explore for, develop and produce crude oil, natural gas and related products around the world. We manage our operations to reflect differences in the regulatory environments and risk factors for each country. Our core operations are onshore in Yemen and Canada, and offshore in the US Gulf of Mexico and Australia. Our other operations are primarily in Nigeria, Colombia, and Brazil. Oil and gas also includes our marketing operations. Marketing sells our own crude oil and natural gas, markets third party crude oil and natural gas and engages in energy trading.

**Syncrude:** We own 7.23% of the Syncrude Joint Venture, which develops and produces synthetic crude oil from oil sands in northern Alberta, Canada.

**Chemicals:** We manufacture, market and distribute industrial chemicals, principally sodium chlorate, chlorine and caustic soda. We produce sodium chlorate at five facilities in Canada, one in the United States and one in Brazil. We produce chlorine and caustic soda at chlor-alkali facilities in Canada and Brazil.

The accounting policies of our operating segments are the same as those described in Note 1. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses. Identifiable assets are those used in the operations of the segments.

## 2002 Operating and Geographic Segments

(Cdn$ millions)

| | Oil and Gas | | | | | | Syncrude | Chemicals | Corporate and Other[a] | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | Yemen | Canada | United States | Australia | Other Countries[b] | Marketing | | | | |
| Net Sales [j] | 789 | 656 | 296 | 165 | 78 | - | 245 | 367[c] | 10 | 2,606 |
| Marketing and Other | - | 2 | - | - | - | 496 | - | 2 | 4 | 504 |
| Gain (Loss) on Disposition of Assets | - | (21)[d] | - | - | - | - | - | - | 13 [e] | (8) |
| Total Revenues | 789 | 637 | 296 | 165 | 78 | 496 | 245 | 369 | 27 | 3,102 |
| Operating | 86 | 176 | 94 | 50 | 22 | - | 115 | 229 | 10 | 782 |
| Transportation and Other | - | - | 3 | - | - | 423 | - | 40 | 3 | 469 |
| General and Administrative | 4 | 22 | 11 | 1 | 19 | 30 | 1 | 21 | 43 | 152 |
| Depreciation, Depletion and Amortization | 149 | 253 | 133 | 53 | 46 | 8 | 13 | 52 | 13 | 720 |
| Exploration | 21 | 38 | 82 | 3 | 45[f] | - | - | - | - | 189 |
| Interest | - | - | - | - | - | - | - | - | 109 | 109 |
| Income (Loss) before Income Taxes | 529 | 148 | (27) | 58 | (54) | 35 | 116 | 27 | (151) | 681 |
| Less: Provision for (Recovery of) Income Taxes[g] | 188 | 59 | (10) | 19 | (18) | 12 | 37 | 9 | (67) | 229 |
| Net Income (Loss) | 341 | 89 | (17) | 39 | (36) | 23 | 79 | 18 | (84) | 452 |
| Identifiable Assets | 600 | 2,124 | 1,452 | 63 | 159 | 811 [h] | 536 | 538 | 277 | 6,560 |
| Capital Expenditures | | | | | | | | | | |
| Development and Other | 209 | 258 | 541 | 46 | 23 | 2 | 141 | 45 | 97[i] | 1,362 |
| Exploration | 22 | 60 | 116 | 3 | 58 | - | - | - | - | 259 |
| Proved Property Acquisitions | - | 4 | - | - | - | - | - | - | - | 4 |
| | 231 | 322 | 657 | 49 | 81 | 2 | 141 | 45 | 97 | 1,625 |
| Property, Plant and Equipment | | | | | | | | | | |
| Cost | 2,054 | 3,098 | 2,186 | 209 | 305 | 86 | 628 | 789 | 213 | 9,568 |
| Less: Accumulated DD&A | 1,646 | 1,137 | 959 | 184 | 198 | 40 | 139 | 345 | 57 | 4,705 |
| Net Book Value [j] | 408 | 1,961 | 1,227 | 25 | 107 | 46 | 489 | 444 | 156 | 4,863 |
| Goodwill | | | | | | | | | | |
| Cost | - | - | - | - | - | 60 | - | - | - | 60 |
| Less: Accumulated DD&A | - | - | - | - | - | 24 | - | - | - | 24 |
| Net Book Value | - | - | - | - | - | 36 | - | - | - | 36 |

Notes:

(a) Includes results of operations from a natural gas-fired generating facility in Alberta.

(b) Includes results of operations from producing activities in Nigeria and Colombia.

(c) Net sales for our chemicals operations include:

| | |
|---|---|
| Canada | $ 251 |
| United States | 56 |
| Brazil | 60 |
| | $ 367 |

(d) On December 30, 2002, we disposed of non-operated oil and gas properties for proceeds of $14 million.

(e) On January 2, 2002, we disposed of our Moose Jaw Asphalt operation for proceeds of $27 million plus working capital.

(f) Includes exploration activities primarily in Nigeria, Colombia and Brazil.

(g) The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

(h) Approximately 70% of Marketing's identifiable assets are accounts receivable.

(i) Includes $67 million related to the buy out of lease agreement related to the construction of a natural gas-fired generating facility in Alberta.

(j) Net sales made from all segments originating in Canada. $ 1,162
Property, plant and equipment located in Canada. $ 2,908

## 2001 Operating and Geographic Segments

(Cdn$ millions)

| | Oil and Gas | | | | | | Syncrude | Chemicals | Corporate and Other[a] | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | Yemen | Canada | United States | Australia | Other Countries[b] | Marketing | | | | |
| Net Sales [g] | 711 | 647 | 358 | 141 | 61 | - | 225 | 373[c] | 77 | 2,593 |
| Marketing and Other | - | 10 | 1 | - | 6 | 438 | - | 3 | 17 | 475 |
| Gain on Disposition of Assets | - | - | 1 | 3 | - | - | - | - | 1 | 5 |
| Total Revenues | 711 | 657 | 360 | 144 | 67 | 438 | 225 | 376 | 95 | 3,073 |
| Operating | 71 | 155 | 66 | 52 | 19 | - | 114 | 243 | 61 | 781 |
| Transportation and Other | - | - | - | - | - | 342 | - | 34 | 24 | 400 |
| General and Administrative | 3 | 25 | 8 | 1 | 21 | 23 | 1 | 18 | 36 | 136 |
| Depreciation, Depletion and Amortization | 111 | 227 | 116 | 65 | 31 | 14 | 12 | 34 | 15 | 625 |
| Exploration | 25 | 44 | 101 | 13 | 82 [d] | - | - | - | - | 265 |
| Interest | - | - | - | - | - | - | - | - | 112 | 112 |
| Income (Loss) before Income Taxes | 501 | 206 | 69 | 13 | (86) | 59 | 98 | 47 | (153) | 754 |
| Less: Provision for (Recovery of) Income Taxes [e] | 185 | 90 | 27 | 5 | (24) | 26 | 32 | 16 | (53) | 304 |
| Net Income (Loss) | 316 | 116 | 42 | 8 | (62) | 33 | 66 | 31 | (100) | 450 |
| Identifiable Assets[f] | 520 | 2,123 | 880 | 47 | 179 | 470 | 399 | 534 | 173 | 5,325 |
| Capital Expenditures | | | | | | | | | | |
| Development and Other | 185 | 367 | 120 | (4) | 23 | - | 60 | 73 | 47 | 871 |
| Exploration | 44 | 84 | 197 | 12 | 74 | - | - | - | - | 411 |
| Proved Property Acquisitions | - | 7 | 115 | - | - | - | - | - | - | 122 |
| | 229 | 458 | 432 | 8 | 97 | - | 60 | 73 | 47 | 1,404 |
| Property, Plant and Equipment | | | | | | | | | | |
| Cost | 1,839 | 2,867 | 1,636 | 167 | 271 | 89 | 487 | 744 | 137 | 8,237 |
| Less: Accumulated DD&A | 1,491 | 913 | 848 | 144 | 166 | 32 | 127 | 296 | 50 | 4,067 |
| Net Book Value [g] | 348 | 1,954 | 788 | 23 | 105 | 57 | 360 | 448 | 87 | 4,170 |
| Goodwill | | | | | | | | | | |
| Cost | - | - | - | - | - | 60 | - | - | - | 60 |
| Less: Accumulated DD&A | - | - | - | - | - | 24 | - | - | - | 24 |
| Net Book Value | - | - | - | - | - | 36 | - | - | - | 36 |

Notes:
(a) Includes results of our Moose Jaw Asphalt operation, which was disposed of on January 2, 2002.
(b) Includes results of operations from producing activities in Nigeria.
(c) Net sales for our chemicals operations include:

| | |
|---|---|
| Canada | $ 241 |
| United States | 90 |
| Brazil | 42 |
| | $ 373 |

(d) Includes exploration activities primarily in Nigeria, Indonesia, and Colombia.
(e) The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.
(f) Approximately 65% of Marketing's identifiable assets are accounts receivable.
(g) Net sales made from all segments originating in Canada. $ 1,190
Property, plant and equipment located in Canada. $ 2,709

## 2000 Operating and Geographic Segments

(Cdn$ millions)

| | Oil and Gas | | | | | | Syncrude | Chemicals | Corporate and Other[a] | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | Yemen | Canada | United States | Australia | Other Countries[b] | Marketing | | | | |
| Net Sales[h] | 752 | 698 | 382 | 167 | 78 | - | 199 | 336[c] | 93 | 2,705 |
| Marketing and Other | 6 | 2 | - | - | 1 | 179 | - | 7 | 25 | 220 |
| Gain on Disposition of Assets | - | 23 | 1 | - | 18[d] | - | - | - | - | 42 |
| Total Revenues | 758 | 723 | 383 | 167 | 97 | 179 | 199 | 343 | 118 | 2,967 |
| Operating | 58 | 135 | 55 | 27 | 22 | - | 98 | 213 | 79 | 687 |
| Transportation and Other | - | - | - | - | - | 131 | - | 34 | 17 | 182 |
| General and Administrative | 3 | 21 | 6 | 1 | 17 | 12 | - | 17 | 40 | 117 |
| Depreciation, Depletion and Amortization | 90 | 233 | 139 | 86 | 40 | 13 | 12 | 40 | 14 | 667 |
| Exploration | 14 | 40 | 60 | 23 | 36[e] | - | - | - | - | 173 |
| Interest | - | - | - | - | - | - | - | - | 132 | 132 |
| Income (Loss) before Income Taxes | 593 | 294 | 123 | 30 | (18) | 23 | 89 | 39 | (164) | 1,009 |
| Less: Provision for (Recovery of) Income Taxes[f] | 219 | 129 | 50 | 11 | (5) | 9 | 29 | 16 | (51) | 407 |
| Net Income (Loss) | 374 | 165 | 73 | 19 | (13) | 14 | 60 | 23 | (113) | 602 |
| Identifiable Assets[g] | 427 | 1,956 | 699 | 91 | 179 | 1,015 | 327 | 506 | 351 | 5,551 |
| Capital Expenditures | | | | | | | | | | |
| Development and Other | 98 | 297 | 81 | - | 9 | 2 | 37 | 31 | 25 | 580 |
| Exploration | 15 | 65 | 143 | 19 | 58 | - | - | - | - | 300 |
| Proved Property Acquisitions | - | 28 | 4 | 3 | - | - | - | - | - | 35 |
| | 113 | 390 | 228 | 22 | 67 | 2 | 37 | 31 | 25 | 915 |
| Property, Plant and Equipment | | | | | | | | | | |
| Cost | 1,555 | 2,497 | 1,242 | 151 | 245 | 88 | 429 | 667 | 89 | 6,963 |
| Less: Accumulated DD&A | 1,314 | 729 | 723 | 90 | 126 | 25 | 118 | 261 | 37 | 3,423 |
| Net Book Value[h] | 241 | 1,768 | 519 | 61 | 119 | 63 | 311 | 406 | 52 | 3,540 |
| Goodwill | | | | | | | | | | |
| Cost | - | - | - | - | - | 60 | - | - | - | 60 |
| Less: Accumulated DD&A | - | - | - | - | - | 18 | - | - | - | 18 |
| Net Book Value | - | - | - | - | - | 42 | - | - | - | 42 |

Notes:

(a) Includes results of our Moose Jaw Asphalt operation which was disposed of on January 2, 2002.

(b) Includes results of operations from producing activities in Nigeria and Ecuador.

(c) Net sales from our chemicals operations include:

| | |
|---|---|
| Canada | $ 237 |
| United States | 76 |
| Brazil | 23 |
| | $ 336 |

(d) On April 18, 2000, Nexen exchanged its oil and gas operations in Ecuador for Occidental's 15% interest in our chemicals operations. The exchange was valued at $55 million. Results of operations from producing activities in Ecuador have been included to April 18, 2000, and operations from the 15% interest in our chemicals operations has been included since April 18, 2000.

(e) Includes exploration activities primarily in Nigeria and Indonesia.

(f) The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

(g) Approximately 70% of Marketing's identifiable assets are accounts receivable.

(h) Net sales made from all segments originating in Canada. $ 1,227
Property, plant and equipment located in Canada. $ 2,472

## 16. DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. Canadian principles differ from US GAAP as follows:

### (a) Consolidated Statement of Income

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Net Income - Canadian GAAP | 452 | 450 | 602 |
| Impact of US Principles: | | | |
| Dividends on Preferred Securities (i) | (72) | (70) | (68) |
| Less: Associated Future Income Taxes | 29 | 31 | 31 |
| Depreciation (ii) | (53) | (46) | (43) |
| Fair Value of Currency Swap, Net of Income Tax (v) | (4) | - | - |
| Net Income - US GAAP (viii) | 352 | 365 | 522 |
| | | | |
| Earnings per Common Share – US GAAP ($/share) | | | |
| Basic | 2.88 | 3.03 | 4.17 |
| Diluted | 2.84 | 2.99 | 4.12 |
| | | | |
| Pro forma Earnings – Fair-value Based Method of Accounting for Stock Options | | | |
| Net Income | | | |
| As Reported | 352 | 365 | 522 |
| Less: Fair Value of Stock Options | 22 | 25 | 14 |
| Pro Forma | 330 | 340 | 508 |
| | | | |
| Earnings Per Common Share ($/share) | | | |
| Basic as Reported | 2.88 | 3.03 | 4.17 |
| Pro Forma | 2.70 | 2.81 | 4.07 |
| | | | |
| Diluted as Reported | 2.84 | 2.99 | 4.12 |
| Pro Forma | 2.67 | 2.79 | 4.01 |

### (b) Consolidated Statement of Comprehensive Income

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Net Income - US GAAP | 352 | 365 | 522 |
| Translation Adjustment, Net of Income Tax (i); (iv) | 34 | (3) | - |
| Minimum Unfunded Pension Liability, Net of Income Tax (vii) | (2) | - | - |
| Comprehensive Income | 384 | 362 | 522 |

### (c) Consolidated Balance Sheet

| | 2002 | | 2001 | |
|---|---|---|---|---|
| | Canadian GAAP | US GAAP | Canadian GAAP | US GAAP |
| Assets | | | | |
| Accounts Receivable (iii) | 988 | 990 | 609 | 616 |
| Property, Plant and Equipment, Net (ii) | 4,863 | 5,064 | 4,170 | 4,424 |
| Deferred Charges and Other Assets (i); (vi) | 69 | 70 | 28 | 51 |
| | | | | |
| Liabilities and Shareholders' Equity | | | | |
| Accounts Payable and Accrued Liabilities (iii); (v) | 1,194 | 1,200 | 773 | 780 |
| Long-Term Debt (i); (vi) | 1,844 | 2,575 | 1,484 | 2,242 |
| Future Income Tax Liabilities (i); (ii) | 873 | 876 | 869 | 878 |
| Preferred Securities (i) | 724 | - | 724 | - |
| Retained Earnings (i); (ii); (v) | 1,069 | 1,280 | 697 | 965 |
| Cumulative Foreign Currency Translation Adjustment (iv) | 115 | - | 94 | - |
| Accumulated Other Comprehensive Income (i);(iv) | - | 92 | - | 60 |

### (d) Consolidated Statement of Cash Flows

Under US principles, dividends on preferred securities of $72 million (2001 - $70 million; 2000 - $68 million) that are included in financing activities would be reported in operating activities.

Under US principles, geological and geophysical costs of $80 million (2001 - $79 million; 2000 - $74 million) that are included in investing activities would be reported in operating activities.

### (e) Changes in Accounting Principles

**Mark-to-Market**

On October 25, 2002, we adopted EITF 02-03, which eliminated mark-to-market accounting as previously defined by EITF 98-10. Mark-to-market accounting was eliminated for our marketing inventories and transportation contracts. We have adopted this change as described in note 1(r). Under EITF 98-10 our results would have been:

| | 2002 |
|---|---|
| Net Income | |
| As Reported | 352 |
| Mark-to-Market on inventory and transportation, net of income taxes | 4 |
| Adjusted | 356 |
| Earnings per Common Share ($/share) | |
| Basic as Reported | 2.88 |
| Adjusted | 2.91 |
| Diluted as Reported | 2.84 |
| Adjusted | 2.88 |

**Goodwill**

On January 1, 2002, we adopted Financial Accounting Standards Board (FASB) Statement No.142, which eliminates goodwill amortization but instead requires annual impairment testing. No goodwill impairment writedowns were required during the year. Our unamortized goodwill at January 1, 2002 was $36 million. The following shows the adjusted net income and earnings per common share had the new standard been applied in 2001 and 2000:

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Net Income | | | |
| As Reported | 352 | 365 | 522 |
| Add: Goodwill Amortization | - | 6 | 5 |
| Adjusted | 352 | 371 | 527 |
| Earnings Per Common Share ($/share) | | | |
| Basic as Reported | 2.88 | 3.03 | 4.17 |
| Adjusted | 2.88 | 3.07 | 4.22 |
| Diluted as Reported | 2.84 | 2.99 | 4.12 |
| Adjusted | 2.84 | 3.04 | 4.16 |

### (f) Recent Developments in US Accounting Standards

In June 2001, FASB issued Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 requires recognition of a liability for the future retirement obligations associated with our property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until we expect to settle the retirement obligation. FAS 143 is effective for all fiscal years beginning after June 15, 2002. The impact on our financial statements at January 1, 2003, is as follows:

| (Cdn$ millions) | Increase /(Decrease) |
|---|---|
| Consolidated Balance Sheet | |
| Property, Plant and Equipment | 123 |
| Asset Retirement Obligation | 185 |
| Future Income Tax Liability | (25) |
| Consolidated Statement of Income | |
| Cumulative Effect of Change in Accounting Principle, Net of Income Taxes | 37 |
| Depreciation, Depletion and Amortization, Net of Income Taxes | 2 |

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 elaborates on the disclosures we must make about our obligations under certain guarantees that we have issued. It also requires us to recognize, at the inception of a guarantee, a liability for the fair value of the obligations we have undertaken in issuing the guarantee. The initial recognition and initial measurement provisions are to be applied only to guarantees issued or modified after December 31, 2002. Adoption of these provisions will not have a material impact on our financial position or results of operations. The disclosure requirements are effective for annual or interim periods ending after December 15, 2002.

In January 2003, the FASB issued Statement No. 148 "Accounting for Stock-Based Compensation - Transition and Disclosure, an Amendment of FASB Statement No. 123" (FAS 148). FAS 148 amends FAS 123 "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, FAS 148 amends the disclosure requirements of FAS 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. FAS 148 has no material impact on us, as we do not plan to adopt the fair value method of accounting for stock options at the current time. We have included the required disclosures in Note 8 to these financial statements.

The following standards issued by the FASB do not impact us:

- Statement No. 145 – "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections", effective for financial statements issued on or after May 15, 2002;
- Statement No. 146 – "Accounting for Costs Associated with Exit or Disposal Activities", effective for exit or disposal activities initiated after December 31, 2002;
- Statement No. 147 – "Acquisitions of Certain Financial Institutions - an Amendment of FASB Statements No. 72 and 144 and FASB Interpretation No. 9", effective for acquisitions on or after October 1, 2002; and
- Interpretation No. 46 – "Consolidation of Variable Interest Entities", effective for financial statements issued after January 31, 2003.

*Notes:*

i. Under US principles, the preferred securities are classified as long-term debt rather than shareholders' equity. The pre-tax dividends are included in interest expense, and the related income tax is included in the provision for income taxes in the Consolidated Statement of Income. The related pre-tax issue costs are included in deferred charges and other assets rather than as an after-tax charge to retained earnings. The foreign-currency translation gains or losses are included in other comprehensive income in the Consolidated Balance Sheet. The pre-tax dividends are included in operating activities in the Consolidated Statement of Cash Flows.

ii. Under US principles, the liability method of accounting for income taxes was adopted in 1993 rather than January 1, 2000, as described in Note 13. Under US principles, the adjustment on initial adoption was included in property, plant and equipment rather than retained earnings. This increases depreciation expense under US principles.

iii. On January 1, 2001, Nexen adopted FASB Statement No. 133 “Accounting for Derivative Instruments and Hedging Activities”, as modified by Statement No. 138 “Accounting for Certain Derivative Instruments and Certain Hedging Activities” (FAS 133). FAS 133 requires us to recognize all derivative instruments on the balance sheet as either an asset or a liability measured at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met. For cash flow hedges, changes in the fair value of derivatives that are designated as hedges are recognized in earnings in the same period as the hedged item. Any fair value change in a derivative before that period is recognized on the balance sheet and in other comprehensive income. For fair value hedges, both the derivative instrument and the underlying commitment are recognized on the balance sheet at their fair value. Any changes in the fair value are reflected net in earnings. Included in both accounts receivable and accounts payable at December 31, 2002 is $2 million (2001 - $7 million) related to fair value hedges. The hedges convert fixed prices for physical delivery of natural gas into a floating price through a fixed to floating swap. The impact on earnings is immaterial.

iv. Under US principles, exchange gains and losses arising from the translation of our net investment in self-sustaining foreign operations are included in comprehensive income. Additionally, exchange gains and losses from translation of our US-dollar long-term debt, net of income taxes, is included in comprehensive income as it has been designated as a hedge of the our foreign net investment. Cumulative amounts are included in accumulated other comprehensive income in the Consolidated Balance Sheet.

v. Under US principles, a derivative and a cash instrument cannot be designated in combination as a net investment hedge. Changes in fair value and foreign exchange gains and losses on our US $37 million currency swap (see note 6) are included in earnings.

vi. Under US principles, discounts on long-term debt are classified as a reduction of long-term debt rather than as deferred charges and other assets.

vii. Under US principles, the amount by which our accrued pension cost is less than the unfunded accumulated benefit obligation is included in comprehensive income and accrued pension liabilities.

viii. Under US principles, gains and losses on the disposition of assets are shown as operating expenses rather than revenues.

## SUPPLEMENTARY FINANCIAL INFORMATION (Unaudited)

### Quarterly Financial Data in Accordance with Canadian and US GAAP

| (Cdn$ millions) | Quarter Ended | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | March 31 | | June 30 | | September 30 | | December 31 | |
| | 2002 | 2001 | 2002 | 2001 | 2002 | 2001 | 2002 | 2001 |
| Net Sales | 541 | 729 | 644 | 692 | 716 | 666 | 705 | 506 |
| Operating Profit | | | | | | | | |
| Oil and Gas [1] | 97 | 304 | 184 | 278 | 223 | 152 | 185 | 28 |
| Syncrude [2] | 20 | 26 | 9 | 23 | 47 | 23 | 40 | 26 |
| Chemicals | 3 | 6 | 4 | 13 | 11 | 17 | 9 | 11 |
| | 120 | 336 | 197 | 314 | 281 | 192 | 234 | 65 |
| Interest and Other Corporate [3] | 24 | 45 | 43 | 40 | 36 | 33 | 48 | 35 |
| Income Tax Expense [4] | 31 | 116 | 53 | 114 | 88 | 74 | 57 | - |
| Net Income in Accordance with Canadian GAAP | 65 | 175 | 101 | 160 | 157 | 85 | 129 | 30 |
| US GAAP Adjustment | (23) | (22) | (22) | (21) | (23) | (21) | (32) | (21) |
| Net Income in Accordance with US GAAP | 42 | 153 | 79 | 139 | 134 | 64 | 97 | 9 |
| Per Common Share ($/share) | | | | | | | | |
| Net Income (Canadian GAAP) | 0.44 | 1.38 | 0.74 | 1.25 | 1.20 | 0.62 | 0.96 | 0.16 |
| Net Income (US GAAP) | 0.35 | 1.27 | 0.65 | 1.15 | 1.09 | 0.53 | 0.79 | 0.08 |
| Dividends Declared [5] | 0.075 | 0.075 | 0.075 | 0.075 | 0.075 | 0.075 | 0.075 | 0.075 |
| Common Share Prices ($/share) | | | | | | | | |
| Toronto Stock Exchange | | | | | | | | |
| High | 39.75 | 39.90 | 42.50 | 40.65 | 42.18 | 41.50 | 37.78 | 35.21 |
| Low | 29.70 | 31.00 | 37.20 | 32.40 | 34.34 | 28.10 | 31.00 | 29.51 |
| New York Stock Exchange | | | | | | | | |
| High (US$) | 25.11 | 25.77 | 28.04 | 26.61 | 27.71 | 26.12 | 23.85 | 22.39 |
| Low (US$) | 18.57 | 20.69 | 23.30 | 20.60 | 21.70 | 17.95 | 19.79 | 18.73 |

Notes:

1. A loss of $21 million was recorded on the disposition of non-operated oil and gas properties during the fourth quarter of 2002.
2. Plant turnarounds and unplanned coker maintenance in the second quarter of 2002 increased operating costs.
3. A gain of $13 million was recorded on the disposition of our Moose Jaw Asphalt operation during the first quarter of 2002.
4. The fourth quarter of 2001 includes a statutory tax rate adjustment for provincial rate reductions in Canada.
5. In February 2003, the Board of Directors declared a regular quarterly dividend of $0.075 per common share, payable April 1, 2003, to shareholders of record on March 10, 2003.
6. At December 31, 2002, there were 1,372 registered holders of common shares and 122,965,830 common shares outstanding.

Nexen AR 2002

## Oil and Gas Netbacks

(Sales prices, per unit costs and netbacks are calculated using our working interest production before royalties.)

| ($/boe) | 2002 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Yemen | Canada | US | Australia | Other | Syncrude | Total |
| Sales | 38.80 | 27.90 | 34.21 | 40.30 | 38.96 | 40.89 | 35.14 |
| Royalties and other | (20.45) | (6.53) | (5.82) | (7.88) | (16.48) | (0.36) | (12.56) |
| Operating expense | (1.95) | (5.70) | (9.09) | (9.76) | (6.21) | (19.09) | (5.48) |
| In-country taxes | (4.81) | - | - | - | - | - | (2.10) |
| Cash netback | 11.59 | 15.67 | 19.30 | 22.66 | 16.27 | 21.44 | 15.00 |

| ($/boe) | 2001 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Yemen | Canada | US | Australia | Other | Syncrude | Total |
| Sales | 35.05 | 26.60 | 39.42 | 38.71 | 37.37 | 39.90 | 33.28 |
| Royalties and other | (18.66) | (6.26) | (6.85) | (2.36) | (7.07) | (1.72) | (11.40) |
| Operating expense | (1.62) | (4.87) | (6.01) | (13.50) | (8.07) | (19.43) | (4.88) |
| In-country taxes | (4.40) | - | - | - | - | - | (1.95) |
| Cash netback | 10.37 | 15.47 | 26.56 | 22.85 | 22.23 | 18.75 | 15.05 |

| ($/boe) | 2000 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Yemen | Canada | US | Australia | Other | Syncrude | Total |
| Sales | 40.53 | 31.10 | 42.43 | 41.05 | 40.12 | 44.84 | 38.05 |
| Royalties and other | (22.14) | (7.48) | (7.70) | - | (8.62) | (7.75) | (13.67) |
| Operating expense | (1.42) | (4.57) | (5.00) | (6.92) | (7.58) | (18.36) | (4.22) |
| In-country taxes | (5.30) | - | - | - | - | - | (2.34) |
| Cash netback | 11.67 | 19.05 | 29.73 | 34.13 | 23.92 | 18.73 | 17.82 |

## OIL AND GAS PRODUCING ACTIVITIES (Unaudited)

The following oil and gas information is provided in accordance with the US Financial Accounting Standards Board Statement No. 69 "Disclosures about Oil and Gas Producing Activities".

### A. Reserve Quantity Information

Our net proved reserves and changes in those reserves are disclosed below. The net proved reserves represent management's best estimate of proved oil and natural gas reserves after royalties. We assess 100% of our reserves estimates internally each year and at least 80% of the reserves have been assessed by independent consultants.

Estimates of conventional crude oil and natural gas proved reserves are determined through analysis of geological and engineering data, demonstrating with reasonable certainty that they are recoverable from known oil and gas fields under economic and operating conditions that exist at year-end. See Critical Accounting Policies and Business Risk Management sections in Item 7 for a discussion of reserves estimation and the related risks.

| | Total | | | Yemen [1] | Canada | | United States | | Australia | Other Countries [2] |
|---|---|---|---|---|---|---|---|---|---|---|
| Oil reserves are in mmbbls and natural gas reserves in bcf | Conventional Oil | Gas | Syncrude [3] | Oil | Oil | Gas | Oil | Gas | Oil | Oil |
| Proved Developed and Undeveloped Reserves [4] | | | | | | | | | | |
| December 31, 1999 | 291 | 614 | 188 | 104 | 150 | 455 | 19 | 159 | 8 | 10 |
| Revisions of Previous Estimates | 26 | 39 | - | 20 | 6 | 18 | 1 | 21 | (1) | - |
| Purchases of Reserves in Place | 7 | 3 | - | - | 5 | - | - | 3 | 2 | - |
| Sales of Reserves In Place | (5) | (1) | - | - | (1) | (1) | - | - | - | (4) |
| Extensions and Discoveries | 26 | 101 | 19 | 2 | 22 | 86 | 2 | 15 | - | - |
| Production | (45) | (83) | (4) | (19) | (16) | (49) | (4) | (34) | (4) | (2) |
| December 31, 2000 | 300 | 673 | 203 | 107 | 166 | 509 | 18 | 164 | 5 | 4 |
| Revisions of Previous Estimates | 1 | - | - | 7 | (14) | (1) | 2 | 1 | 1 | 5 |
| Purchases of Reserves in Place | 2 | 64 | - | - | 2 | 3 | - | 61 | - | - |
| Sales of Reserves in Place | - | (2) | - | - | - | (2) | - | - | - | - |
| Extensions and Discoveries | 53 | 146 | 34 | 17 | 21 | 91 | 11 | 55 | - | 4 |
| Production | (47) | (90) | (6) | (20) | (18) | (54) | (3) | (36) | (4) | (2) |
| December 31, 2001 | 309 | 791 | 231 | 111 | 157 | 546 | 28 | 245 | 2 | 11 |
| Revisions of Previous Estimates | (6) | (10) | (12) | (14) | 7 | (6) | 1 | (4) | - | - |
| Purchases of Reserves in Place | - | 1 | - | - | - | 1 | - | - | - | - |
| Sales of Reserves in Place | (6) | (1) | - | - | (2) | (1) | - | - | - | (4) |
| Extensions and Discoveries | 72 | 103 | 13 | 23 | 10 | 31 | 32 | 72 | 5 | 2 |
| Production | (45) | (81) | (6) | (20) | (16) | (47) | (3) | (34) | (4) | (2) |
| December 31, 2002 | 324 | 803 | 226 | 100 | 156 | 524 | 58 | 279 | 3 | 7 |
| Proved Developed Reserves [5] | | | | | | | | | | |
| December 31, 2000 | 223 | 613 | 183 | 77 | 120 | 463 | 17 | 150 | 5 | 4 |
| December 31, 2001 | 223 | 676 | 212 | 70 | 126 | 505 | 18 | 171 | 2 | 7 |
| December 31, 2002 | 246 | 702 | 196 | 61 | 131 | 487 | 46 | 215 | 3 | 5 |

Notes:

1 Under the terms of the Masila production sharing contract, production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all our costs and those of our partners. Remaining production is profit oil, which is shared between the partners and the Government of Yemen based on production rates, with the partners' share ranging from 20% to 33%. The Government's share of profit oil represents their royalty interest and an amount for income taxes payable in Yemen. Yemen's net proved reserves include our share of future cost recovery and profit oil after the Government's royalty interest but before reserves relating to income taxes payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) since the barrels necessary to achieve cost recovery change with prevailing oil prices.

2 Represents reserves in Nigeria and Colombia. (2001 – Nigeria and Colombia; 2000 – Nigeria; 1999 – Nigeria and Ecuador.)

3 US Securities and Exchange Commission regulations define these reserves as mining-related and not part of conventional oil and gas reserves. For management purposes, we view these reserves and their development as integral to our oil and gas operations. These reserves are not considered in the standardized measure of discounted future net cash flows, which follows. In 2002, Syncrude moved to generic royalty terms that provide for a royalty of 25% on net revenues after all costs have been recovered, subject to a minimum 1% gross royalty. Under this royalty regime, reported reserves will increase as oil prices decrease (and vice versa) since the barrels necessary to recover costs change with prevailing oil prices.

4 "Proved" oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically, as demonstrated by either actual production or conclusive formation tests.

5 "Proved developed" oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

## B. Capitalized Costs

| (Cdn$ millions) | Proved Properties | Unproved Properties | Accumulated Depreciation, Depletion and Amortization | Capitalized Costs |
|---|---|---|---|---|
| December 31, 2002 | | | | |
| Yemen | 2,024 | 30 | 1,646 | 408 |
| Canada | 2,882 | 216 | 1,137 | 1,961 |
| United States | 2,061 | 125 | 959 | 1,227 |
| Australia | 209 | - | 184 | 25 |
| Other Countries | 251 | 54 | 198 | 107 |
| Syncrude | 628 | - | 139 | 489 |
| Total | 8,055 | 425 | 4,263 | 4,217 |
| December 31, 2001 | | | | |
| Yemen | 1,808 | 31 | 1,491 | 348 |
| Canada | 2,750 | 117 | 913 | 1,954 |
| United States | 1,522 | 114 | 848 | 788 |
| Australia | 167 | - | 144 | 23 |
| Other Countries | 267 | 4 | 166 | 105 |
| Syncrude | 487 | - | 127 | 360 |
| Total | 7,001 | 266 | 3,689 | 3,578 |
| December 31, 2000 | | | | |
| Yemen | 1,544 | 11 | 1,314 | 241 |
| Canada | 2,344 | 153 | 729 | 1,768 |
| United States | 1,154 | 88 | 723 | 519 |
| Australia | 151 | - | 90 | 61 |
| Other Countries | 184 | 61 | 126 | 119 |
| Syncrude | 429 | - | 118 | 311 |
| Total | 5,806 | 313 | 3,100 | 3,019 |

## C. Costs Incurred

| (Cdn$ millions) | Total | | Conventional Oil and Gas | | | | |
|---|---|---|---|---|---|---|---|
| | Conventional Oil and Gas | Syncrude | Yemen | Canada | United States | Australia | Other Countries |
| Year Ended December 31, 2002 | | | | | | | |
| Property Acquisition Costs | | | | | | | |
| Proved | 4 | - | - | 4 | - | - | - |
| Unproved | 31 | - | - | - | 31 | - | - |
| Exploration Costs | 228 | - | 22 | 60 | 85 | 3 | 58 |
| Development Costs | 1,077 | 141 | 209 | 258 | 541 | 46 | 23 |
| | 1,340 | 141 | 231 | 322 | 657 | 49 | 81 |
| Year Ended December 31, 2001 | | | | | | | |
| Property Acquisition Costs | | | | | | | |
| Proved | 122 | - | - | 7 | 115 | - | - |
| Unproved | 37 | - | 19 | - | 18 | - | - |
| Exploration Costs | 374 | - | 25 | 84 | 179 | 12 | 74 |
| Development Costs | 691 | 60 | 185 | 367 | 120 | (4) | 23 |
| | 1,224 | 60 | 229 | 458 | 432 | 8 | 97 |
| Year Ended December 31, 2000 | | | | | | | |
| Property Acquisition Costs | | | | | | | |
| Proved | 35 | - | - | 28 | 4 | 3 | - |
| Unproved | 39 | - | - | - | 31 | - | 8 |
| Exploration Costs | 261 | - | 15 | 65 | 112 | 19 | 50 |
| Development Costs | 485 | 37 | 98 | 297 | 81 | - | 9 |
| | 820 | 37 | 113 | 390 | 228 | 22 | 67 |

## D. Results of Operations for Producing Activities

| (Cdn$ millions) | Total | | Conventional Oil and Gas | | | | |
|---|---|---|---|---|---|---|---|
| | Conventional Oil and Gas | Syncrude | Yemen | Canada | United States | Australia | Other Countries |
| **Year Ended December 31, 2002** | | | | | | | |
| Net Sales | 1,984 | 245 | 789 | 656 | 296 | 165 | 78 |
| Production Costs | 428 | 115 | 86 | 176 | 94 | 50 | 22 |
| Exploration Expense | 189 | - | 21 | 38 | 82 | 3 | 45 |
| Depreciation, Depletion and Amortization | 634 | 13 | 149 | 253 | 133 | 53 | 46 |
| Other Expenses (Income) | 79 | 1 | 4 | 41 | 14 | 1 | 19 |
| | 654 | 116 | 529 | 148 | (27) | 58 | (54) |
| Income Tax Provision (Recovery) | 238 | 37 | 188 | 59 | (10) | 19 | (18) |
| Results of Operations | 416 | 79 | 341 | 89 | (17) | 39 | (36) |
| **Year Ended December 31, 2001** | | | | | | | |
| Net Sales | 1,918 | 225 | 711 | 647 | 358 | 141 | 61 |
| Production Costs | 363 | 114 | 71 | 155 | 66 | 52 | 19 |
| Exploration Expense | 265 | - | 25 | 44 | 101 | 13 | 82 |
| Depreciation, Depletion and Amortization | 550 | 12 | 111 | 227 | 116 | 65 | 31 |
| Other Expenses (Income) | 37 | 1 | 3 | 15 | 6 | (2) | 15 |
| | 703 | 98 | 501 | 206 | 69 | 13 | (86) |
| Income Tax Provision (Recovery) | 283 | 32 | 185 | 90 | 27 | 5 | (24) |
| Results of Operations | 420 | 66 | 316 | 116 | 42 | 8 | (62) |
| **Year Ended December 31, 2000** | | | | | | | |
| Net Sales | 2,077 | 199 | 752 | 698 | 382 | 167 | 78 |
| Production Costs | 297 | 98 | 58 | 135 | 55 | 27 | 22 |
| Exploration Expense | 173 | - | 14 | 40 | 60 | 23 | 36 |
| Depreciation, Depletion and Amortization | 588 | 12 | 90 | 233 | 139 | 86 | 40 |
| Other Expenses (Income) | (3) | - | (3) | (4) | 5 | 1 | (2) |
| | 1,022 | 89 | 593 | 294 | 123 | 30 | (18) |
| Income Tax Provision (Recovery) | 404 | 29 | 219 | 129 | 50 | 11 | (5) |
| Results of Operations | 618 | 60 | 374 | 165 | 73 | 19 | (13) |

## E. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

The following disclosure includes estimates of net proved reserves and the period during which they are expected to be produced. Future cash inflows are computed by applying year-end prices to our after royalty share of estimated annual future production from proved conventional oil and gas reserves (excluding Syncrude). Future development and production costs to be incurred in producing and further developing the proved reserves are based on year-end cost indicators. Future income taxes are computed by applying year-end statutory-tax rates. These rates reflect allowable deductions and tax credits and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-period discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proven to be the case in the past. Other assumptions could give rise to substantially different results.

We believe that this information does not in any way reflect the current economic value of our oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from year-end levels.

| (Cdn$ millions) | Total | Yemen | Canada | United States | Australia | Other Countries |
|---|---|---|---|---|---|---|
| December 31, 2002 | | | | | | |
| Future Cash Inflows | 18,687 | 4,662 | 9,067 | 4,516 | 144 | 298 |
| Future Production and Development Costs | 4,892 | 1,177 | 2,568 | 913 | 108 | 126 |
| Future Income Tax | 3,650 | 790 | 1,976 | 863 | - | 21 |
| Future Net Cash Flows | 10,145 | 2,695 | 4,523 | 2,740 | 36 | 151 |
| 10% Discount Factor | 3,776 | 819 | 2,081 | 818 | 1 | 57 |
| Standardized Measure | 6,369 | 1,876 | 2,442 | 1,922 | 35 | 94 |
| December 31, 2001 | | | | | | |
| Future Cash Inflows | 10,337 | 3,068 | 5,034 | 1,880 | 64 | 291 |
| Future Production and Development Costs | 4,123 | 880 | 1,943 | 1,000 | 64 | 236 |
| Future Income Tax | 1,520 | 661 | 751 | 96 | - | 12 |
| Future Net Cash Flows | 4,694 | 1,527 | 2,340 | 784 | - | 43 |
| 10% Discount Factor | 1,607 | 385 | 1,004 | 202 | - | 16 |
| Standardized Measure | 3,087 | 1,142 | 1,336 | 582 | - | 27 |
| December 31, 2000 | | | | | | |
| Future Cash Inflows | 15,173 | 3,552 | 8,113 | 3,166 | 220 | 122 |
| Future Production and Development Costs | 3,574 | 741 | 2,103 | 550 | 112 | 68 |
| Future Income Tax | 3,783 | 897 | 2,093 | 760 | 18 | 15 |
| Future Net Cash Flows | 7,816 | 1,914 | 3,917 | 1,856 | 90 | 39 |
| 10% Discount Factor | 2,825 | 507 | 1,835 | 474 | 4 | 5 |
| Standardized Measure | 4,991 | 1,407 | 2,082 | 1,382 | 86 | 34 |

### Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

| (Cdn$ millions) | 2002 | 2001 | 2000 |
|---|---|---|---|
| Beginning of Year | 3,087 | 4,991 | 3,801 |
| Sales and Transfers of Oil and Gas Produced, Net of Production Costs | (1,158) | (2,012) | (1,425) |
| Net Changes in Prices and Production Costs Related to Future Production | 3,083 | (2,871) | 1,255 |
| Extensions, Discoveries and Improved Recovery, Less Related Costs | 1,929 | 691 | 536 |
| Development Costs Incurred during the Period | 322 | 61 | 341 |
| Revisions of Previous Quantity Estimates | 267 | (33) | 670 |
| Accretion of Discount | 409 | 736 | 534 |
| Purchases of Reserves in Place | 2 | 161 | 119 |
| Sales of Reserves in Place | (109) | (1) | (47) |
| Net Change in Income Taxes | (1,463) | 1,364 | (793) |
| End of Year | 6,369 | 3,087 | 4,991 |

## Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

On June 3, 2002, the Canadian firm of Deloitte & Touche LLP (Deloitte Canada) completed a transaction with the Canadian firm of Arthur Andersen LLP (Andersen Canada) to integrate partners and staff of Andersen Canada into Deloitte Canada. On July 11, 2002, our Board accepted the resignation of Andersen Canada and appointed Deloitte Canada as our auditors until the next Annual General Meeting.

There were no disagreements with accountants on accounting and financial disclosure.

## PART III

### Item 10. Directors and Executive Officers of the Registrant

#### DIRECTORS OF THE REGISTRANT

According to our Articles, Nexen must have between three and 15 directors. On February 13, 2003, the directors determined that from May 6, 2003, until changed, there will be ten directors.

Our By-Laws provide that directors will be elected at the annual general meeting of shareholders each year and will hold office until their successors have been duly elected. All of our current directors were elected at the last annual general meeting except for Mr. O'Neill, who was appointed by the Board on December 10, 2002. The following directors are management nominees for election to the Board.

This table shows each director's principal occupation or employment during the past five years and any other directorships they held in public companies as at February 13, 2003.

| Name (Age) | Principal Occupation and Other Directorships | Director Since |
|---|---|---|
| Charles W. Fischer (52) | President and Chief Executive Officer of Nexen. Formerly, Executive Vice President and Chief Operating Officer. | 2000 |
| Dennis G. Flanagan (63) | Retired oil executive. Director of NAL Royalty Trust. | 2000 |
| David A. Hentschel (69) | Retired Chairman and Chief Executive Officer of Occidental Oil and Gas Corporation. Consultant to Occidental Petroleum Corporation and a director of Cimarex Energy Co. | 1985 |
| S. Barry Jackson (50) | Retired oil executive. Formerly, President and Chief Executive Officer and a director of Crestar Energy Inc. Director and Executive Chairman of Resolute Energy Inc. and a director of TransCanada Pipelines Limited. | 2001 |
| Kevin J. Jenkins (46) | Formerly, President and Chief Executive Officer and a director of The Westaim Corporation. | 1996 |
| Thomas C. O'Neill (57) | Retired Chairman of PwC Consulting. Formerly, Chief Executive Officer of PwC Consulting. Prior to that, Chief Operating Officer of PricewaterhouseCoopers LLP, Global. Prior to that, Chief Executive Officer of PricewaterhouseCoopers LLP, Canada and, prior to that, Chairman and Chief Executive Officer of Price Waterhouse Canada. Director of BCE Inc. and Ontario Teachers' Pension Plan Board. | 2002 |
| Francis M. Saville, Q.C. (64) | Vice Chairman and Senior Partner of Fraser Milner Casgrain LLP, Barristers and Solicitors. Director of Mullen Transportation Inc. | 1994 |
| Richard M. Thomson (69) | Retired banking executive. Director of the Toronto-Dominion Bank, Prudential Financial Inc., INCO Limited, The Thomson Corporation, Trizec Properties Inc. and Stuart Energy Systems Inc. | 1997 |
| John M. Willson (63) | Retired President and Chief Executive Officer of Placer Dome Inc. Formerly, President and Chief Executive Officer of Pegasus Gold Inc. Director of Finning International Inc. and PanAmerican Silver Corp. | 1996 |
| Victor J. Zaleschuk (59) | Retired President and Chief Executive Officer of Nexen. Director of Cameco Corporation and Agrium Inc. | 1997 |

Mr. Gordon R. Wittman, age 72, retired President, Chief Operating Officer and a director of Dupont Canada Inc., will not be standing for re-election to the Board, as he has reached Nexen's mandatory retirement age. Mr. Wittman has been a valued member of the Board since 1994. The Board and Management wish to thank Mr. Wittman for his dedicated service to Nexen and its shareholders.

### Independence and Board Committees

The following table summarizes the independence of Board members and sets out their Committee memberships as of February 13, 2003. Independence was affirmatively determined by the Board in reference to the categorical standards of independence adopted on February 13, 2003 (Categorical Standards). The Categorical Standards are attached as Schedule B to Nexen's Proxy Statement and Information Circular. The Categorical Standards are consistent with the Toronto Stock Exchange guidelines for "outside" and "unrelated" directors, provisions of the Sarbanes-Oxley Act of 2002 and proposed New York Stock Exchange rules.

| | Audit and Conduct Review [1] | Corporate Governance and Nominating | Finance | Compensation and Human Resources | Reserves Review | Safety, Environment and Social Responsibility |
|---|---|---|---|---|---|---|
| **OUTSIDE DIRECTORS** | | | | | | |
| **Independent** | | | | | | |
| Dennis G. Flanagan [2, 3] | ✓ | ✓ | ✓ | | Chair | |
| David A. Hentschel | Chair | | | ✓ | ✓ | ✓ |
| S. Barry Jackson [4] | ✓ | | | ✓ | ✓ | ✓ |
| Kevin J. Jenkins [2] | | ✓ | Chair | ✓ | | ✓ |
| Thomas C. O'Neill [2] | ✓ | ✓ | | ✓ | | ✓ |
| Francis M. Saville, Q.C. | | Chair | ✓ | | ✓ | ✓ |
| Richard M. Thomson [2, 5] | ✓ | ✓ | ✓ | ✓ | | |
| John M. Willson | | | ✓ | Chair | ✓ | ✓ |
| Gordon R. Wittman | ✓ | ✓ | | ✓ | | Chair |
| **Not Independent** | | | | | | |
| Victor J. Zaleschuk [6] | | ✓ | ✓ | ✓ | ✓ | |
| **INSIDE DIRECTORS** | | | | | | |
| **Not Independent** | | | | | | |
| Charles W. Fischer [7] | | | | | | |
| **MEETINGS IN 2002** | **6** | **5** | **5** | **4** | **3** | **4** |

Notes:

1 All members of the Audit and Conduct Review Committee are also independent under additional requirements for audit committee members.

2 Qualifies as a "financial expert" under US regulatory requirements.

3 Mr. Flanagan is a member of the Audit Committee of NAL Royalty Trust.

4 Mr. Jackson is Executive Chairman of Resolute Energy Inc. (Resolute). Annual sales from Resolute to Nexen are minimal in respect to Nexen, but represent more than 1% and less than 5% of the annual revenues of Resolute. As this exceeds the limit of presumed independence set out in section 2 of the Categorical Standards, the directors who are presumed independent considered the circumstances of the relationship between Nexen and Resolute, as allowed for under section 3 of the Categorical Standards. They determined that the relationship was not material and Mr. Jackson was deemed to be independent. Among the circumstances considered by the directors were: the ongoing competitive market for the commodities purchased and the services provided by Nexen; the commodity prices are based on indices at various delivery points, the price for services is competitive and both are negotiated at arms-length; and Mr. Jackson had no involvement in the negotiation of the purchase and services agreements. The directors also confirmed that Mr. Jackson met the additional independence requirements applicable to members of the Audit and Conduct Review Committee.

5 Mr. Thomson is a member of the Audit Committee of one other public company, Trizec Properties Inc.

6 Mr. Zaleschuk is not independent as he was the President and Chief Executive Officer of Nexen until May 31, 2001. He will be independent after June 1, 2006.

7 Mr. Fischer is not independent as he is the President and Chief Executive Officer of Nexen.

During 2002, there were nine meetings and two resolutions in writing of the Board. There was 100% attendance at all Board and Committee meetings.

## Committee Responsibilities

Each Committee makes regular reports to the Board and, if required, other Committees, concerning its activities. Each Committee is authorized to engage independent counsel or other advisors as needed. Below is a description of the responsibilities of each of the Board Committees.

The **Audit and Conduct Review Committee** assists the Board in fulfilling its oversight responsibilities with respect to (i) the integrity of the annual and quarterly financial statements to be provided to shareholders and regulatory bodies; (ii) Nexen's compliance with accounting and finance based legal and regulatory requirements; (iii) the independent auditor's qualifications and independence; (iv) the system of internal accounting and financial reporting controls that management has established; and (v) the performance of the internal and external audit process and the independent auditor. In addition, the Committee provides an avenue for communication between each of internal audit, the independent auditors, financial and senior management and the Board.

The **Corporate Governance and Nominating Committee** assists the Board in fulfilling its oversight responsibilities with respect to (i) the development and implementation of principles and systems for the management of corporate governance; and (ii) identifying qualified candidates and recommending nominees for director and board committee appointments.

The **Finance Committee** assists the Board in fulfilling its oversight responsibilities with respect to (i) financial policies and strategies including capital structure; (ii) financial risk management practices; and (iii) transactions or circumstances which could materially affect Nexen's financial profile.

The **Compensation and Human Resources Committee** assists the Board in fulfilling its oversight responsibilities with respect to (i) human resources policies; (ii) executive management compensation; and (iii) executive management succession and development.

The **Reserves Review Committee** assists the Audit and Conduct Review Committee and the Board in fulfilling their oversight responsibilities with respect to the annual review of Nexen's petroleum and natural gas reserves.

The **Safety, Environment and Social Responsibility Committee** assists the Board in fulfilling its oversight responsibilities with respect to due diligence in the development and implementation of systems for the management of safety, environment and social responsibility.

Mandates for each of the Committees are reviewed annually and updated, as appropriate, to reflect current responsibilities and practices. The mandates for all of the Committees of the Board, together with the Board Mandate and the Chair Mandate/Position Description, are attached as Schedule C to Nexen's Proxy Statement and Information Circular.

## Ethics Policy

Pursuant to Nexen's Ethics Policy all directors, officers and employees must demonstrate a commitment to ethical business practices and behaviour in all business relationships, both within and outside of Nexen. No employee, regardless of his or her position, is ever expected to commit an unethical, dishonest or illegal act or to instruct other employees to do so. We confirm that our Ethics Policy has been adopted as a code of ethics applicable to our principal executive officer, principal financial officer and principal accounting officer or controller. Any waivers of or changes to the Ethics Policy must be approved by the Board and appropriately disclosed.

Our Ethics Policy is available on our internet website at www.nexeninc.com and it is our intention to provide disclosure in this manner.

## Audit and Conduct Review Committee Report

The Audit and Conduct Review Committee is directly responsible for the appointment (subject to shareholder approval), compensation and oversight of the independent auditors. The independent auditors report directly to the Committee. The Committee has a clear understanding with the independent auditors that they must maintain an open and transparent relationship with the Committee and that the ultimate accountability of the independent auditors is to the Committee, as representatives of the shareholders. A copy of the mandate of the Committee is included in Schedule C to Nexen's Proxy Statement and Information Circular.

The Committee is composed of six directors, all of whom are independent pursuant to Nexen's categorical standards which include the additional requirements for independence of audit committee members set out in the Sarbanes-Oxley Act of 2002.

Management is responsible for Nexen's internal controls and financial reporting process. The independent auditors are responsible for performing and reporting on an independent audit of Nexen's Consolidated Financial Statements in accordance with generally accepted auditing standards. The Committee's responsibility is to monitor and oversee these processes.

In connection with their responsibilities, the Committee:

- met with management and the independent auditors to review and discuss the December 31, 2002 Consolidated Financial Statements;
- discussed with the independent auditors the matters required by Canadian regulators in accordance with Section 5751 of the General Assurance and Auditing Standards of the Canadian Institute of Chartered Accountants "Communications with Those Having Oversight Responsibility for the Financial Reporting Process" and by US regulators in accordance with the Statement on Auditing Standards No. 61 "Communication with Audit Committees" issued by the American Institute of Certified Public Accountants;
- received written disclosures from the independent auditors required by the US Securities and Exchange Commission in accordance with the Independence Standards Board Standard No. 1 "Independence Discussions with Audit Committees"; and
- discussed with the independent auditors that firm's independence.

**Change in Auditor**

On June 3, 2002, the Canadian firm of Deloitte & Touche LLP completed a transaction with the Canadian firm of Arthur Andersen LLP to integrate partners and staff of Arthur Andersen LLP (Canada) into Deloitte & Touche LLP (Canada). On July 11, 2002, our Board accepted the resignation of Arthur Andersen LLP (Canada) and appointed Deloitte & Touche LLP (Canada) as Nexen's auditors until the next Annual General Meeting.

**Audit Fees**

Total audit related fees billed by Nexen's independent auditors, Deloitte & Touche LLP, during 2002 were:

- $550,000 for the annual audit of Nexen's Consolidated Financial Statements included in our 2002 Annual Report on Form 10-K;
- $31,000 for the second and third quarter reviews of Nexen's consolidated financial statements included in our Form 10-Qs for the periods ended June 30, 2002 and September 30, 2002, respectively;
- $231,500 for the annual audits of subsidiary financial statements and employee benefit plans; and
- $4,000 for comfort letters to commissions.

Total audit related fees billed by Nexen's former independent auditors, Arthur Andersen LLP, during 2002 were:

- $13,000 for the first quarter review of Nexen's consolidated financial statements included in our Form 10-Q for the period ended March 31, 2002; and
- $88,300 for comfort letters to commissions.

**Financial Information Systems Design and Implementation Fees**

Deloitte & Touche LLP did not provide any financial information systems design and implementation services as described in Paragraph (c)(4)(ii) of Rule 2-01 of Regulation S-X under US federal securities laws for the fiscal year ended December 31, 2002.

**All Other Fees**

Total fees billed by Deloitte & Touche LLP for other services during 2002 were:

- $72,550 for tax return preparation assistance and tax-related consultation.

Total fees billed by Arthur Andersen LLP for other services during 2002 were:

- $106,601 for tax preparation assistance and tax-related consultation; and
- $62,900 for assisting the internal audit group with its evaluation of the implementation of an enterprise-wide resource system.

**General**

The Committee considered and is of the view that the provision of services by Deloitte & Touche LLP described in "All Other Fees" above is compatible with maintaining that firm's independence.

Based on the Committee's discussions with management and the independent auditors, and its review of the representations of management and the independent auditors, the Committee recommended that the Board include the audited Consolidated Financial Statements in Nexen's Annual Report on Form 10-K for the year ended December 31, 2002.

Submitted on behalf of the Audit and Conduct Review Committee:

David A. Hentschel, Chair
Dennis G. Flanagan
S. Barry Jackson
Thomas C. O'Neill
Richard M. Thomson
Gordon R. Wittman

## Director Compensation

Since January 1, 2000, all directors who are not employees are paid:

- an annual retainer of $28,100 for services on the Board and $1,800 for each Board meeting attended; and
- an annual retainer of $9,100 for service on each Committee and $1,800 for each Committee meeting attended.

The Chair of the Board is paid an annual retainer of $108,000 and the Chair of each Committee is paid an additional annual retainer of $5,300. Director compensation was last reviewed in December 2001. At that time, retainers and fees were not increased.

In 2001, a Deferred Share Unit (DSU) plan was approved as an alternative form of compensation for non-employee directors. Under the plan, eligible directors may elect, on an annual basis, to receive all or part of their fees in the form of DSUs, rather than cash. A DSU is a bookkeeping entry which tracks the value of one Nexen common share. DSUs are not paid out until the director leaves the Board, thereby providing an ongoing equity stake in Nexen during the director's term of service. Payments of DSUs may be made in cash or in Nexen common shares purchased on the open market at the time of payment.

In December 2002, all directors who were not employees of Nexen were granted 5,500 stock options, except for the Chair of the Board, who was granted 8,300 stock options. The exercise price of the options was $33.93 and the options expire December 9, 2007.

## EXECUTIVE OFFICERS OF THE REGISTRANT

Past positions, in order from most recent to earliest, are set out for officers who have not held their current executive positions with Nexen for more than 5 years. Start dates are indicated for officer positions with Nexen.

| Officer (Age) | Current and Past Position(s) with Nexen | Effective Date of Current Position | Executive Officer Since |
|---|---|---|---|
| Charles W. Fischer (52) | President and Chief Executive Officer and a Director<br>Formerly: Executive Vice President and Chief Operating Officer since May 14, 1997 | June 1, 2001 | 1994 |
| Marvin F. Romanow (47) | Executive Vice President and Chief Financial Officer<br>Formerly: Senior Vice President, Finance since February 19, 1999<br>Vice President, Finance and Chief Financial Officer since February 27, 1998<br>Vice President, Finance since June 17, 1997 | June 1, 2001 | 1997 |
| Laurence Murphy (52) | Senior Vice President, International Oil and Gas<br>Formerly: Vice President, International since February 27, 1998<br>President and General Manager of Yemen Operations | January 1, 1999 | 1998 |
| John B. McWilliams[1] (55) | Senior Vice President, General Counsel and Secretary | May 11, 1993 | 1987 |

| Officer (Age) | Current and Past Position(s) with Nexen | Effective Date of Current Position | Executive Officer Since |
|---|---|---|---|
| Douglas B. Otten (60) | Senior Vice President, United States Oil and Gas<br>Formerly: Senior Vice President since May 14, 1997 | May 12, 1998 | 1990 |
| Thomas A. Sugalski [1] (59) | Senior Vice President, Chemicals | May 10, 1994 | 1988 |
| Roger D. Thomas (50) | Senior Vice President, Canadian Oil and Gas<br>Formerly: Vice President, Canada since May 12, 1998<br>Vice President since January 1, 1998 | February 19, 1999 | 1998 |
| Nancy F. Foster (43) | Vice President, Human Resources and Corporate Services<br>Formerly: Division Vice President, Finance – Canadian Oil and Gas<br>General Manager, Human Resources<br>Corporate Manager, Planning and Development | July 11, 2000 | 2000 |
| Gary H. Nieuwenburg (44) | Vice President, Synthetic Crude<br>Formerly: Vice President, Corporate Planning and Business Development since February 16, 2001<br>Division Vice President, Exploration and Production – Canadian Oil and Gas<br>Division Vice President, Exploration and Production Technology – Canadian Oil and Gas | July 11, 2002 | 2001 |
| Kevin J. Reinhart (44) | Vice President, Corporate Planning and Business Development<br>Formerly: Treasurer since October 20, 1998<br>Controller since May 10, 1994 | July 11, 2002 | 1994 |
| Una M. Power [2] (38) | Treasurer<br>Formerly: Controller and Director, Corporate Insurance since May 2, 2002<br>Controller and Director, Risk Management since December 1, 1998<br>Manager, Financial Reporting | July 11, 2002 | 1998 |
| Michael J. Harris (39) | Controller<br>Formerly: Manager, Corporate Finance – Treasury<br>Division Vice President, Finance – International | December 10, 2002 | 2002 |

Notes:
1 Officer has held the same executive position with Nexen for more than 5 years.
2 Ms. Power concurrently maintained her position as Controller until December 10, 2002.
3 The term of office of each executive officer is determined by the Board.

## Item 11. Executive Compensation

### SUMMARY COMPENSATION

This table summarizes the compensation earned by Nexen's Chief Executive Officer and the four highest compensated officers other than the Chief Executive Officer.

| Name and Principal Position | Year | Annual Compensation | | | Long-Term Compensation | | All Other Compensation ($) |
|---|---|---|---|---|---|---|---|
| | | | | | Awards | | |
| | | Salary ($) | Bonus [1] ($) | Other Annual Compensation ($) | Securities Underlying Options Granted (#) | Restricted Shares or Restricted Share Units ($) | |
| Charles W. Fischer<br>President and Chief<br>Executive Officer | 2002<br>2001<br>2000 | 637,500<br>540,667<br>430,000 | 300,000<br>400,000<br>700,000[2] | -<br>-<br>- | 100,000<br>105,000<br>70,000 | -<br>-<br>- | 38,250 [3]<br>32,440 [3]<br>25,800 [3] |
| Marvin F. Romanow<br>Executive Vice President<br>and Chief Financial<br>Officer | 2002<br>2001<br>2000 | 418,000<br>376,333<br>322,500 | 310,000<br>225,000<br>570,000[2] | -<br>-<br>- | 50,000<br>60,000<br>50,000 | -<br>-<br>- | 25,080 [3]<br>22,582 [3]<br>19,350 [3] |
| Douglas B. Otten<br>Senior Vice President,<br>United States Oil and Gas | 2002<br>2001<br>2000 | 485,873<br>456,783<br>422,372 | 125,886<br>405,685<br>218,854 | -<br>-<br>- | 35,000<br>28,000<br>40,000 | -<br>-<br>- | 29,156 [3] / 63,005 [4]<br>27,407 [3] / 79,874 [4]<br>10,985 [3] / 56,648 [4] |
| Thomas A. Sugalski<br>Senior Vice President,<br>Chemicals | 2002<br>2001<br>2000 | 449,993<br>422,908<br>390,547 | 118,019<br>232,240<br>194,870 | -<br>417,695 [6]<br>- | 30,000<br>25,000<br>35,000 | -<br>-<br>- | 26,999 [3] / 60,889 [5]<br>25,374 [3] / 76,059 [5]<br>15,290 [3] / 49,306 [5] |
| Laurence Murphy<br>Senior Vice President,<br>International Oil and Gas | 2002<br>2001<br>2000 | 346,000<br>329,250<br>311,250 | 90,000<br>180,000<br>162,000 | -<br>-<br>- | 35,000<br>28,000<br>40,000 | -<br>-<br>- | 20,760 [3]<br>19,758 [3]<br>18,675 [3] |

Notes:

1 Bonuses for a year are determined based on performance during the year and are paid to the employee in the following year. Bonuses are paid pursuant to the Incentive Compensation Plan. The bonuses indicated were the payments made in the year shown.

2 Includes a special bonus of $400,000 in recognition of the successful share repurchase transaction with Occidental Petroleum Corporation.

3 Contributions to the Employee Savings Plan.

4 Nexen contributed to a Qualified Defined Contribution Plan and a Restoration Plan with Nexen Petroleum U.S.A. Inc. for Mr. Otten.

5 Nexen contributed to a Qualified Defined Contribution Plan in 2001 and 2002 for Mr. Sugalski. Nexen contributed to the Occidental Petroleum Corporation Senior Executive Supplemental Retirement Plan for Mr. Sugalski during 2000 and to the Nexen Chemicals U.S.A. Inc. Restoration Plan in 2001 and 2002.

6 Represents a special settlement payment for termination from Occidental Petroleum Corporation Non-Qualified Executive Benefit Plans.

## Stock Options

Pursuant to Nexen's Stock Option Plan, the Board, on the recommendation of the Compensation and Human Resources Committee, may grant stock options to Nexen directors, officers and employees. Nexen does not receive any consideration when options are granted. The option exercise price is the market price of Nexen's common shares on the Toronto Stock Exchange for Canadian based employees or the New York Stock Exchange for US based employees, when the option is granted.

The Board determines the term of each option, to a maximum of ten years, and the vesting schedule. For all options granted before December 31, 2000, each option has a term of ten years; 20% of the grant vests after six months and then 20% more vests each year for four years on the anniversary of the grant. In February 2001, the Compensation and Human Resources Committee and the Board approved an amendment to the Stock Option Plan which sets out that each option granted has a term of five years and the options vest one-third each year over three years. Generally, if a change of control event occurs (as defined in the Stock Option Plan), all issued but unvested options will become vested.

### Option Grants During 2002

| Name | Securities Underlying Options Granted (#) | % of Total Options/Stock Appreciation Rights Granted to Employees in Financial Year | Exercise or Base Price [1] ($/Security) [2] | Expiration Date | Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term | |
|---|---|---|---|---|---|---|
| | | | | | 5% ($) | 10% ($) |
| Charles W. Fischer | 100,000 | 3.7 | 33.93 | December 9, 2007 | 937,423 | 1,626,960 |
| Marvin F. Romanow | 50,000 | 1.9 | 33.93 | December 9, 2007 | 468,712 | 813,480 |
| Douglas B. Otten | 35,000 | 1.3 | 21.89 (USD) | December 9, 2007 | 333,085 | 554,196 |
| Thomas A. Sugalski | 30,000 | 1.1 | 21.89 (USD) | December 9, 2007 | 285,501 | 475,025 |
| Laurence Murphy | 35,000 | 1.3 | 33.93 | December 9, 2007 | 328,098 | 569,436 |

Notes:

[1] Equal to the market value of securities underlying options on the date of grant.

[2] All values in Canadian dollars unless otherwise noted.

### Option Exercises During 2002 And Financial Year-end Option Values

| Name | Securities Acquired on Exercise (#) | Value Realized [1] ($) [2] | Number of Securities Underlying Unexercised Options at Financial Year-end (#) Exercisable / Unexercisable | Value of Unexercised In-The-Money-Options at Financial Year-end ($)[2] Exercisable / Unexercisable |
|---|---|---|---|---|
| Charles W. Fisher | 8,000 | 204,000 | 328,100 / 211,300 | 2,799,840 / 292,360 |
| Marvin F. Romanow | 13,000 | 297,270 | 134,400 / 127,600 | 881,360 / 176,940 |
| Douglas B. Otten | - | - | 181,320 / 76,480 | 1,885,964 / 102,216 |
| Thomas A. Sugalski | 62,000 | 1,246,850 | 114,500 / 67,500 | 716,827 / 96,514 |
| Laurence Murphy | - | - | 134,520 / 76,480 | 1,014,722 / 117,118 |

Notes:

[1] Equals market price at the time of the exercise minus exercise price.

[2] All values in Canadian dollars.

## Benefit Plans

All named executive officers, except Mr. Sugalski and Mr. Otten, are members of Nexen's Defined Benefit Pension Plan and of the Executive Benefit Plan.

### Defined Benefit Pension Plan

Under this plan, participants must contribute 3% of their regular gross earnings, up to an allowable maximum, to the pension plan. Upon retirement, they receive a benefit equal to 1.7% of their average earnings for the 36 highest paid consecutive months during the ten years before retirement, multiplied by the number of years of credited service. The plan is integrated with the Canada Pension Plan (CPP) in order to provide a maximum offset of one-half of the CPP benefit.

Pension benefits earned prior to January 1, 1993 will be indexed on an ad hoc basis. Pension benefits earned after December 31, 1992 will be indexed at an amount equal to the greater of:

- 75% of the increase in the Canadian Consumer Price Index less 1% to a maximum of 5%; and
- 25% of the increase in the Canadian Consumer Price Index.

Nexen contributed $1.9 million to the Defined Benefit Pension Plan in 2002.

### Executive Benefit Plan

The plan provides supplemental benefits to the extent that benefits under the pension plan are limited by statutory guidelines.

### Estimated Pension Benefit

This table shows the estimated annual pension an executive officer who retired on December 31, 2002 would receive, assuming that the amount in the Summary Compensation Table above is the officer's final average salary. It includes benefits from both the Defined Benefit Pension Plan and Executive Benefit Plan and assumes a retirement age of 65. The normal form of benefit paid from this plan is joint life with 66 ⅔% to the surviving spouse.

| | Years of Service | | | | | | |
|---|---|---|---|---|---|---|---|
| REMUNERATION | 5 | 10 | 15 | 20 | 25 | 30 | 35 |
| $300,000 | $24,824 | $49,648 | $74,472 | $99,296 | $124,120 | $148,944 | $173,768 |
| $350,000 | $29,074 | $58,148 | $87,222 | $116,296 | $145,370 | $174,444 | $203,518 |
| $400,000 | $33,324 | $66,648 | $99,972 | $133,296 | $166,620 | $199,944 | $233,268 |
| $450,000 | $37,574 | $75,148 | $112,722 | $150,296 | $187,870 | $225,444 | $263,018 |
| $500,000 | $41,824 | $83,648 | $125,472 | $167,296 | $209,120 | $250,944 | $292,768 |
| $550,000 | $46,074 | $92,148 | $138,222 | $184,296 | $230,370 | $276,444 | $322,518 |
| $600,000 | $50,324 | $100,648 | $150,972 | $201,296 | $251,620 | $301,944 | $352,268 |
| $650,000 | $54,574 | $109,148 | $163,722 | $218,296 | $272,870 | $327,444 | $382,018 |
| $700,000 | $58,824 | $117,648 | $176,472 | $235,296 | $294,120 | $352,944 | $411,768 |
| $750,000 | $63,074 | $126,148 | $189,222 | $252,296 | $315,370 | $378,444 | $441,518 |
| $800,000 | $67,324 | $134,648 | $201,972 | $269,296 | $336,620 | $403,944 | $471,268 |
| $850,000 | $71,574 | $143,148 | $214,722 | $286,296 | $357,870 | $429,444 | $501,018 |
| $900,000 | $75,824 | $151,648 | $227,472 | $303,296 | $379,120 | $454,944 | $530,768 |
| $950,000 | $80,074 | $160,148 | $240,222 | $320,296 | $400,370 | $480,444 | $560,518 |
| $1,000,000 | $84,324 | $168,648 | $252,972 | $337,296 | $421,620 | $505,944 | $590,268 |
| $1,050,000 | $88,574 | $177,148 | $265,722 | $354,296 | $442,870 | $531,444 | $620,018 |
| $1,100,000 | $92,824 | $185,648 | $278,472 | $371,296 | $464,120 | $556,944 | $649,768 |
| $1,150,000 | $97,074 | $194,148 | $291,222 | $388,296 | $485,370 | $582,444 | $679,518 |
| $1,200,000 | $101,324 | $202,648 | $303,972 | $405,296 | $506,620 | $607,944 | $709,268 |

An executive officer's average earnings for purposes of the plan includes stated salary and the lesser of the eligible target incentive bonus or the actual incentive bonus paid.

Messrs. Fischer, Romanow and Murphy have 18.58, 15.50 and 16.67 years of credited service, respectively.

## Employee Savings Plan

The Summary Compensation Table includes Nexen's contribution to the savings plan made on behalf of executive officers. All regular employees may participate in our Employee Savings Plan. Through payroll deductions, employees may contribute any percentage of their regular earnings to purchase Nexen common shares and/or mutual fund units. Nexen matches employee contributions to a maximum of 6% of regular earnings. The extent of matching is based on the investment option selected and the employee's length of participation in the plan. The full amount of Nexen's contribution is invested in common shares and is fully vested immediately. Employee and employer contributions may be allocated to registered or non-registered accounts.

## Change of Control Agreements

Nexen has entered into Change of Control Agreements with Messrs. Fischer, Romanow, Otten, Sugalski, Murphy and other key executives. The agreements were effective October 1999, amended December 2000 and amended and restated December 2001. The agreements recognize that these executives are critical to Nexen's ongoing business. They recognize the need to retain the executives, protect them from employment interruption due to a change in control and treat them in a fair and equitable manner, consistent with industry standards.

For the purposes of these agreements, a change of control includes any acquisition of common shares or other securities that carry the right to cast more than 35% of the votes attaching to all common shares and, in general, any event, transaction or arrangement which results in a person or group exercising effective control of Nexen.

If the named executives are terminated following a change in control, they will be entitled to receive salary and benefits for a specified severance period. For Mr. Fischer and Mr. Romanow, the severance period is 36 months. They may also terminate their employment on a voluntary basis following a change of control with severance periods of 36 and 30 months, respectively. For Messrs. Otten, Sugalski and Murphy, the severance period is 30 months.

## Directors' and Officers' Liability Insurance

Nexen maintains a directors' and officers' liability insurance policy for the benefit of our directors and officers. The policy provides coverage for costs incurred to defend and settle claims against its directors and officers to an annual limit of US $125 million with a US $1 million deductible per occurrence. The cost of coverage for 2002 was approximately US $0.3 million.

# REPORT OF THE COMPENSATION AND HUMAN RESOURCES COMMITTEE

The Compensation and Human Resources Committee administers Nexen's Incentive Compensation Plan, Stock Option Plan, Stock Appreciation Rights Plan and Pension Plan. It reviews and approves executive management's recommendations for the annual salaries, bonuses and grants of stock options and stock appreciation rights. The Committee consists of eight directors, seven who are independent pursuant to Nexen's categorical standards and one who is not independent. Both Mr. Hentschel and Mr. Zaleschuk were formerly President and Chief Executive Officer of Nexen (Mr. Hentschel over five years ago). The Committee reports to the Board and the Board gives final approval to compensation matters.

## Policies of the Committee

Nexen is committed to pay for performance, improved shareholder returns and external competitiveness. These principles are factored into the design, development and administration of our compensation programs, as directed by the Committee.

The Committee believes maximizing shareholder return is the most important measure of success. At the operational level, this translates primarily into net income, cash flow and net asset value growth. At the corporate headquarters level, this results from successful implementation of necessary strategic change. The Committee recognizes the need to attract and retain a stable and focused leadership capable of managing Nexen's operations, finances and assets. As appropriate, the Committee rewards exceptional individual contributions with highly competitive compensation.

To ensure competitiveness, Nexen hires various independent compensation consulting firms to compare our executive compensation practices to our peers, primarily major Canadian oil and gas and, where relevant, chemical and marketing companies.

Our compensation program has three components: salary, annual cash incentives and long-term incentives.

## Base Salaries

To determine base salaries, Nexen maintains a framework of job levels based on internal comparability and external market data. The Committee's goal is to provide total cash compensation for our top performing employees between the $50^{th}$ and $75^{th}$ percentile as compared to our peers.

## Annual Incentives

The Board approves any annual cash incentives awarded under the Annual Incentive Plan. The Committee determines the total amount of cash available for annual incentive awards by evaluating a combination of financial and non-financial criteria, including net income, operating cash flow and specific strategic goals outlined in a balanced scorecard. The primary indicators, net income and cash flow, are commonly used metrics in our industry and each represents one-third of the overall assessment. The qualitative assessment of the balanced scorecard performance indicators provides a comprehensive evaluation and accounts for the final one-third of the overall performance assessment. Individual target award levels increase in relation to job responsibilities so that the ratio of at-risk versus fixed compensation is greater for higher levels of management. Individual awards are intended to reflect a combination of overall Nexen, personal and business unit performance, along with market competitiveness.

The incentive plan is reviewed annually to ensure the plan continues to attract, motivate, reward and retain the high performing and high potential employees needed to achieve Nexen's business objectives, while reflecting long-term fiscal responsibility to our shareholders.

## Stock and Long-Term Incentives

The Board believes that employees should have a stake in Nexen's future and that their interest should be aligned with the interest of our shareholders. To this end, Nexen's contributions to employee savings plans are made in Nexen common shares. In addition, the Committee selects those directors, officers and employees whose decisions and actions can most directly impact business results to participate in the Stock Option Plan and the Stock Appreciation Rights Plan.

Under these plans, participating directors, officers and employees receive grants of stock options or stock appreciation rights as a long-term incentive to increase shareholder value. The grants have a five-year term and vest one-third each year of the first three years of the term on the anniversary date of the grant. Awards of stock options and stock appreciation rights are supplementary to the Annual Incentive Plan and are intended to increase the pay-at-risk component for senior management.

The Stock Appreciation Rights Plan was introduced in 2001. For employees at or below mid-level department managers, these rights are typically granted instead of stock options.

To determine the number of stock options available for distribution, we consider market information on stock options and the impact of the program on shareholders. The focus in 2002 was on providing differentiated awards based on performance, potential and retention risk.

Nexen's Stock Option Plan sets out that options granted to non-officer directors will not exceed 0.25% of total outstanding shares. The Stock Option Plan also sets out the total options granted and shares reserved for issuance under stock-based compensation arrangements will not exceed 10% of the total outstanding shares.

Nexen maintains share ownership guidelines for executive officers as a way of aligning executive and shareholder interests. The Chief Executive Officer, Chief Financial Officer and other executive officers are expected to own shares representing three, two and one times annual base salary, respectively. In determining compliance with the guidelines, share ownership includes the net value of exercisable options.

## President and Chief Executive Officer Compensation

Competitive compensation information for our President and Chief Executive Officer is determined based on assessments conducted by independent compensation consulting firms which compare similar positions in oil and gas and in the broader industrial sector. Target total cash compensation (base salary plus incentive bonus) is at the low end of the range of the oil and gas comparator group.

The award to Mr. Fischer under the Annual Incentive Plan, is a percentage of his target bonus based on the composite performance rating approved by the Board which takes into account the three components of the plan, the first two being the targets for net income and cash flow and the last one being a qualitative assessment. The qualitative assessment includes a scorecard of targets for growth and operating performance, such as net asset value growth, cost management, safety record, production volumes and reserve growth, among others. An important measure in the scorecard is the extent to which the operations were conducted in an environmentally safe and socially responsible manner.

Annual salary increases for Mr. Fischer are based on his performance against key objectives using a broad selection of criteria including the following:

- overall achievement of corporate/financial performance;
- achievement of strategic objectives;
- progress on long term objectives;
- team building and succession planning;
- visionary leadership; and
- social responsibility.

Based on the Board assessment of Mr. Fischer's achievement of objectives in 2001, his base salary was increased to $650,000 in 2002 and he was awarded a bonus of $300,000 under the Annual Incentive Plan.

Mr. Fischer was also granted options to purchase 100,000 shares at an exercise price of $33.93 under the Nexen Stock Option Plan. Awards under the Stock Option Plan are a direct link to the stock performance and form a part of the competitive overall compensation package.

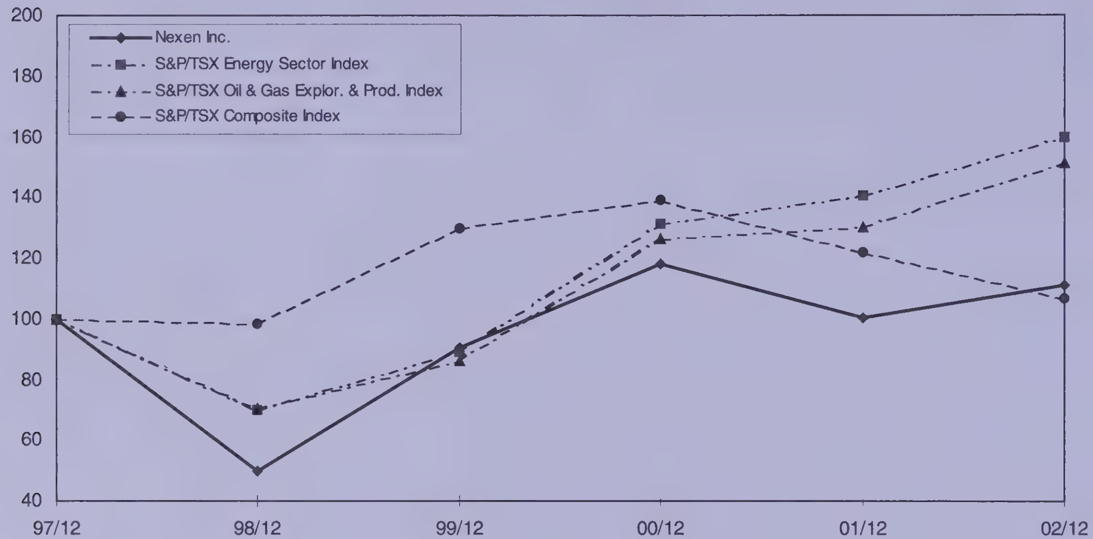
Submitted on behalf of the Compensation and Human Resources Committee:

Mr. John M. Willson, Chair
Mr. David A. Hentschel
Mr. S. Barry Jackson
Mr. Kevin J. Jenkins
Mr. Thomas C. O'Neill
Mr. Richard M. Thomson
Mr. Gordon R. Wittman
Mr. Victor J. Zaleschuk

### New Share Performance Graph

The following graph shows changes in the past five year period, ending December 31, 2002, in the value of $100 invested in our common shares, compared to the S&P/TSX Composite Index (previously known as the TSE 300 Composite Index), the S&P/TSX Energy Sector Index (as a replacement for the TSX Oil and Gas Index) and the S&P/TSX Oil & Gas Exploration & Production Index (as a replacement for TSX Oil and Gas Producers Index) as at December 31, 2002. Our common shares are included in each of these indices.

**Total Return Index Values**



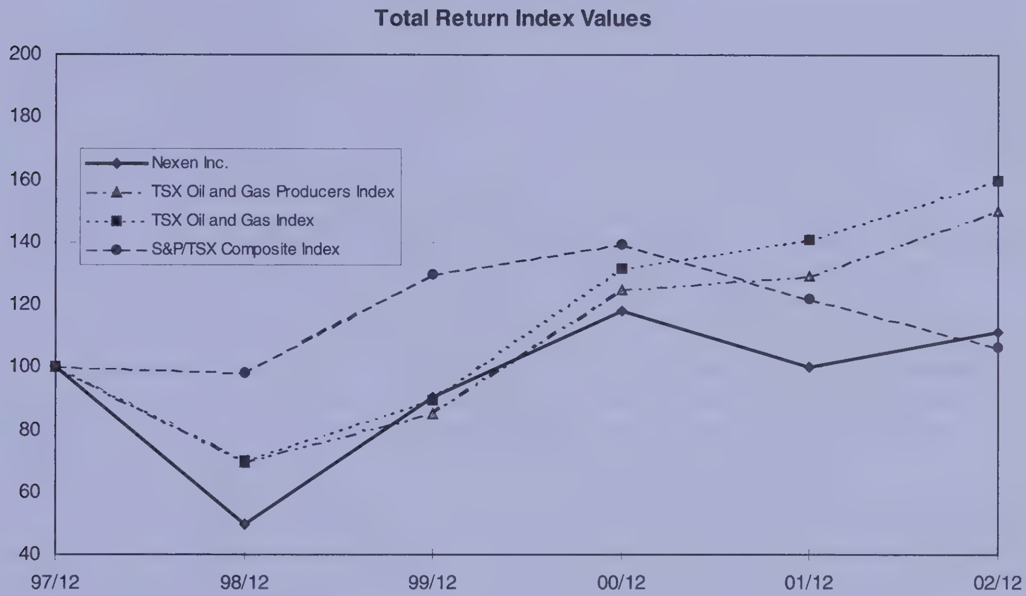

| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|---|---|
| Nexen Inc. | 100.00 | 49.79 | 90.38 | 118.27 | 100.25 | 111.36 |
| S&P/TSX Energy Sector Index | 100.00 | 70.12 | 88.96 | 131.39 | 140.47 | 159.77 |
| S&P/TSX Oil & Gas Explor. & Prod. Index | 100.00 | 70.21 | 85.92 | 126.34 | 130.42 | 151.51 |
| S&P/TSX Composite Index | 100.00 | 98.42 | 129.63 | 139.23 | 121.73 | 106.59 |

Assuming an investment of $100 and the reinvestment of dividends

### Old Share Performance Graph

The following graph shows changes in the past five year period, ending December 31, 2002, in the value of $100 invested in our common shares, compared to the S&P/TSX Composite Index (previously known as the TSE 300 Composite Index) and the TSX Oil and Gas and TSX Oil and Gas Producers Indices as at December 31, 2002. Our common shares are included in each of these indices.

In 2004, Nexen intends to abandon the TSX Oil and Gas and the TSX Oil and Gas Producers Indices as they will not be maintained after May 2003 and they are not accessible to shareholders. Nexen will continue to compare its shares to each of the indices shown on the previous page, being the S&P/TSX Composite Index, the S&P/TSX Energy Sector Index (as a replacement for the TSX Oil and Gas Index) and the S&P/TSX Oil & Gas Exploration & Production Index (as a replacement for TSX Oil and Gas Producers Index).




| | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|---|---|
| Nexen Inc. | 100.00 | 49.79 | 90.38 | 118.27 | 100.25 | 111.36 |
| TSX Oil and Gas Producers Index | 100.00 | 69.59 | 85.26 | 124.89 | 129.12 | 150.09 |
| TSX Oil and Gas Index | 100.00 | 70.15 | 89.27 | 131.43 | 140.64 | 159.95 |
| S&P/TSX Composite Index | 100.00 | 98.42 | 129.63 | 139.23 | 121.73 | 106.59 |

Assuming an investment of $100 and the reinvestment of dividends

## Item 12. Security Ownership of Certain Beneficial Owners and Management

### SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

Nexen's common shares are the only class of voting securities of Nexen. Based upon information known to Nexen, the following table sets out the beneficial ownership of each person or group who beneficially owns (pursuant to SEC Regulations) more than 5% of the voting securities of Nexen as of December 31, 2002.

| Name and Address of Beneficial Owner [1] | # of Shares Beneficially Owned | % of Class |
|---|---|---|
| Jarislowsky Fraser Limited [2]<br>Suite 2005, 1010 Sherbrooke Street West<br>Montreal, Quebec, Canada, H3A 2R7 | 19,781,235 | 16.1 |
| Ontario Teachers' Pension Plan Board [3]<br>5650 Yonge Street<br>Toronto, Ontario, Canada, M2M 4H5 | 19,720,418 | 16.0 |
| Capital Research and Management Co. [4]<br>333 South Hope Street<br>Los Angeles, California, U.S.A., 90071-1447 | 9,052,520 | 7.4 |

Notes:

[1] Beneficial owners holding greater than 5% of the outstanding common shares of Nexen are derived from public sources. There may exist Beneficial owners who hold more than 5% of Nexen's common shares who are not subject to 13-D and 13-G filing requirements.

[2] Of the 19,781,235 beneficially owned, the beneficial owner has sole voting power over 18,638,418 shares; shared voting power over 1,142,817 shares; and sole dispositive power over all of the 19,781,235 shares.

[3] The beneficial owner has sole voting and dispositive power over all of the 19,720,418 shares.

[4] The beneficial owner has sole dispositive power over all of the 9,052,520 shares and disclaims beneficial ownership pursuant to Rule 13d-4.

### SECURITY OWNERSHIP OF MANAGEMENT

As of January 31, 2003, the following directors, certain executive officers and all directors and executive officers as a group beneficially owned the following common shares of Nexen (which are the only voting securities):

| Name of Beneficial Owner | Number of Shares [1] | Exercisable Stock Options [1, 2] |
|---|---|---|
| Charles W. Fischer | 22,806 | 328,100 |
| Dennis G. Flanagan | 3,001 | 11,210 |
| David A. Hentschel | 5,585 | 19,210 |
| S. Barry Jackson | 3,000 | 2,210 |
| Kevin J. Jenkins | 3,021 | 19,210 |
| Thomas C. O'Neill | 4,000 | None |
| Francis M. Saville, Q.C. | 3,151 | 19,210 |
| Richard M. Thomson | 13,001 | 28,832 |
| John M. Willson | 5,001 | 19,210 |
| Gordon R. Wittman | 3,001 | 19,210 |
| Victor J. Zaleschuk | 15,539 | 253,010 |
| Laurence Murphy | 19,305 | 134,520 |
| Douglas B. Otten | 12,148 | 181,320 |
| Marvin F. Romanow | 12,006 | 144,400 |
| Thomas A. Sugalski | 17 | 114,500 |
| All directors and executive officers as a group (22 persons) | 165,205 | 1,662,782 |

Notes:

[1] The number of shares and the number of stock options exercisable by each beneficial owner represents less than 1% of the class outstanding.

[2] Includes all stock options exercisable within 60 days of January 31, 2003.

## Item 13. Certain Relationships and Related Transactions

### CERTAIN BUSINESS RELATIONSHIPS

Mr. Saville, a director, is a senior partner of Fraser Milner Casgrain LLP, Barristers and Solicitors, Calgary, Alberta. This firm has rendered legal services to Nexen during each of the last five years. Mr. Saville is independent pursuant to the categorical standards adopted by Nexen. The categorical standards are attached as Schedule B to our Proxy Statement and Information Circular.

## Item 14. Controls and Procedures

### EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-14(c) and 15-d-14(c)) within 90 days prior to the filing of this Form 10-K (Evaluation Date). They concluded that, as of the Evaluation Date, our disclosure controls and procedures were adequate and effective in ensuring that material information relating to the Company and its consolidated subsidiaries would be made known to them by others within those entities, particularly during the period in which this annual report was being prepared. Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and in reaching a reasonable level of assurance, management necessarily is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

### CHANGES IN INTERNAL CONTROLS

We have continually had in place systems relating to internal controls and procedures with respect to our financial information. While we were not of the belief that our controls had any significant deficiencies or material weaknesses, it was determined that taking advantage of new proven systems technology could provide a competitive advantage. Accordingly, in 2002, we introduced a significant change in our internal controls implementing a Systems, Applications, and Products in Data Processing (SAP) system in Canada (January 1, 2002), in the Yemen Masila Project (April 1, 2002) and in the US (July 1, 2002). SAP is being implemented in other locations throughout 2003 and beyond. SAP is an integrated, real-time, multi-user, multi-location enterprise resource planning system, which focuses on financial and management accounting, and logistics. The conversion of data and the implementation and operation of SAP has been continually monitored and reviewed. Based on these evaluations, there were no significant deficiencies or material weaknesses in these internal controls requiring corrective action. As a result, no corrective actions were taken.

## PART IV

### Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

#### FINANCIAL STATEMENTS AND SCHEDULES

Reference is made to the Index to Financial Statements and Related Information under Item 8 of this report where these documents are listed.

Schedules and separate financial statements of subsidiaries are omitted for the reason that they are not required or are not applicable, or the required information is shown in the Consolidated Financial Statements or notes thereto.

#### EXHIBITS

Exhibits filed as part of this report are listed below. Certain exhibits have been previously filed with the Commission and are incorporated in this Form 10-K by reference. Instruments defining the rights of holders of debt securities that do not exceed 10% of Nexen's consolidated assets have not been included. A copy of such instruments will be furnished to the Commission upon request.

3.5 Restated Certificate of Incorporation of the Registrant dated June 5, 1995, and Restated Articles of Incorporation (filed as Exhibit 3.5 to Form 10-K for the year ended December 31, 1995, filed by the Registrant).

3.6 Certificate of Amendment of the Articles of the Registrant dated May 9, 1996 (filed as Exhibit 3.6 to Form 10-K for the year ended December 31, 1996, filed by the Registrant).

3.7 Certificate of Amendment and Articles of Amendment of the Registrant dated November 2, 2000, with respect to the name change to Nexen Inc. (filed as Exhibit 3.7 to Form 10-K for the year ended December 31, 2000, filed by the Registrant).

3.8 By-Law No. 1 of the Registrant enacted February 15, 2002, being a by-law relating generally to the transaction of the business and affairs of the Registrant (filed as Exhibit 2 to Form 8A/A dated August 20, 2002, filed by the Registrant).

4.23 Indenture dated October 30, 1998, between the Registrant and IBJ Stirred Bank & Trust Company pertaining to the issuance of US $259 million, 9.75 per cent junior subordinated debentures ("preferred securities") due October 30, 2047, (filed as Exhibit 4.23 to Form 10-Q for the quarterly period ended March 31, 1999, filed by the Registrant).

4.24 Prospectus dated October 27, 1998, pertaining to US $259 million, 9.75 per cent preferred securities due October 30, 2047, (filed as Exhibit 4.24 to Form 10-Q for the quarterly period ended March 31, 1999, filed by the Registrant).

4.25 Indenture dated February 9, 1999, between the Registrant and IBJ Whitehall Bank & Trust Company pertaining to the issuance of US $218 million, 9.375 per cent preferred securities due March 31, 2048, (filed as Exhibit 4.25 to Form 10-Q for the quarterly period ended March 31, 1999, filed by the Registrant).

4.26 Prospectus dated February 4, 1999, pertaining to US $218 million, 9.375 per cent preferred securities due March 31, 2048, (filed as Exhibit 4.26 to Form 10-Q for the quarterly period ended March 31, 1999, filed by the Registrant).

4.29 Acquisition Agreement between the Registrant, Occidental Petroleum Corporation and Ontario Teachers' Pension Plan Board, dated March 1, 2000, (filed as Exhibit 4.29 to Form 10-K for the year ended December 31, 1999, filed by the Registrant).

4.32 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated November 17, 2000, amending the amount of the facility to $400 million and providing for various conforming covenant amendments to the Loan Agreement dated April 14, 1997, (as restated) thereto (filed as Exhibit 4.32 to Form 10-K for the year ended December 31, 2000, filed by the Registrant).

4.33 Restated Loan Agreement of April 14, 1997, between the Registrant, Toronto Dominion Bank, as Agent, and the Lenders dated October 16, 2000, reducing the amount of the facility to $975 million and splitting the loan into 364 day (40%) and six year term (60%) portions, and other various amendments thereto (filed as Exhibit 4.33 to Form 10-K for the year ended December 31, 2000, filed by the Registrant).

4.36 First Amending Agreement to the October 16, 2000 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Banks, as Agent, and the Lenders, dated July 31, 2001 (filed as Exhibit 4.36 to Form 10-K for the year ended December 31, 2001, filed by the Registrant).

4.37 First Amending Agreement to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated August 1, 2001 (filed as Exhibit 4.37 to Form 10-K for the year ended December 31, 2001, filed by the Registrant).

4.38 Second Amending Agreement to the October 16, 2000 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Banks, as Agent, and the Lenders, dated July 30, 2002.

4.39 Second Amending Agreement to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated July 31, 2002.

4.40 Amended and Restated Shareholder Rights Plan Agreement dated May 2, 2002 between the Corporation and CIBC Mellon Trust Company, as Rights Agent, which includes the Form of Rights Certificate as Exhibit A (filed as Exhibit 3 to Form 8-A/A dated August 20, 2002, filed by the Registrant).

4.41 Short Form Shelf Prospectus dated May 31, 2002, pertaining to US $500 million debt securities.

10.40 Amended and Restated Change of Control Agreements with Executive Officers dated during December, 2001 (filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2001, filed by the Registrant).

10.41 Indemnification Agreements made between the Registrant and its directors and officers during 2002.

11.2 Statement regarding the Computation of Per Share Earnings for the three years ended December 31, 2002.

16.1 Letter re change in certifying accountant (filed as Exhibit 16.1 to Form 8-K filed July 17, 2002 by the Registrant).

21 Subsidiaries of the Registrant.

23 Consent of Independent Chartered Accountants.

99.1 Certification of periodic report by Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.2 Certification of periodic report by Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

## REPORTS ON FORM 8-K

During the fourth quarter of 2002, Nexen did not file a Current Report on Form 8-K.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 24, 2003.

**NEXEN INC.**

By: /s/ Charles W. Fischer
Charles W. Fischer
President, Chief Executive Officer
and Director (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 24, 2003.

/s/ Dennis G. Flanagan
Dennis G. Flanagan, Director

/s/ Kevin J. Jenkins
Kevin J. Jenkins, Director

/s/ David A. Hentschel
David A. Hentschel, Director

/s/ S. Barry Jackson
S. Barry Jackson, Director

/s/ Thomas C. O'Neill
Thomas C. O'Neill, Director

/s/ Francis M. Saville
Francis M. Saville, Director

/s/ Richard M. Thomson
Richard M. Thomson, Director

/s/ John M. Willson
John M. Willson, Director

/s/ Gordon R. Wittman
Gordon R. Wittman, Director

/s/ Victor J. Zaleschuk
Victor J. Zaleschuk, Director

/s/ Charles W. Fischer
Charles W. Fischer
President, Chief Executive Officer
and Director (Principal Executive Officer)

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Michael J. Harris
Michael J. Harris
Controller
(Principal Accounting Officer)

/s/ John B. McWilliams
John B. McWilliams
Senior Vice President, General Counsel
and Secretary

## CERTIFICATIONS

I, Charles W. Fischer, President and Chief Executive Officer, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:
   (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date); and
   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 24, 2003

/s/ Charles W. Fischer
Charles W. Fischer
President, and Chief Executive Officer

## CERTIFICATIONS

I, Marvin F. Romanow, Executive Vice-President, and Chief Financial Officer, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:
   (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the Evaluation Date"); and
   (c) presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):
   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and
   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and
6. The registrant's other certifying officers and I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 24, 2003

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President,
and Chief Financial Officer

Historic results verify

continued profitability,

## HISTORICAL REVIEW (unaudited)

| (amounts in millions except per share data) | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|
| **Highlights** | | | | | |
| Net Sales | $ 2,606 | $ 2,593 | $ 2,705 | $ 1,646 | $ 1,472 |
| Cash Flow from Operations | $ 1,383 | $ 1,423 | $ 1,569 | $ 780 | $ 600 |
| Per Common Share(1) | $ 10.71 | $ 11.20 | $ 12.01 | $ 5.19 | $ 4.34 |
| Net Income (Loss) | $ 452 | $ 450 | $ 602 | $ 100 | $ (110) |
| Per Common Share(1) | $ 3.34 | $ 3.40 | $ 4.52 | $ 0.46 | $ (0.83) |
| Capital Expenditures | $ 1,625 | $ 1,404 | $ 915 | $ 612 | $ 950 |
| Acquisitions | $ – | $ – | $ 39 | $ 91 | $ – |
| Dispositions | $ 49 | $ 5 | $ 42 | $ 85 | $ 533 |
| **Operations** | | | | | |
| Daily Production(2) | | | | | |
| Crude Oil and NGLs (mbbls/d) | 223 | 219 | 210 | 193 | 196 |
| Natural Gas (mmcf/d) | 279 | 295 | 274 | 278 | 420 |
| Total (mboe/d)(3) | 269 | 268 | 256 | 239 | 266 |
| **Proved Reserves(2)** | | | | | |
| Crude Oil and NGLs (mmbbls) | 696 | 692 | 679 | 655 | 605 |
| Natural Gas (bcf) | 939 | 943 | 805 | 726 | 755 |
| Total (mmboe)(3) | 853 | 849 | 813 | 776 | 731 |
| F&D Costs – Annual ($/boe)(4) | $ 13.63 | $ 9.47 | $ 6.31 | $ 4.00 | $ 5.05 |
| F&D Costs – 3-Yr Avg ($/boe) | $ 9.58 | $ 6.44 | $ 5.09 | $ 5.17 | $ 6.20 |
| F&D Costs – 5-Yr Avg ($/boe) | $ 7.25 | $ 6.13 | $ 5.71 | $ 5.48 | $ 5.59 |
| Reserve Replacement Costs – Annual ($/boe)(4) | $ 14.40 | $ 9.50 | $ 6.04 | $ 3.73 | $ 3.39 |
| Reserve Replacement (%) | 104 | 137 | 140 | 151 | 116 |
| **Financial Position** | | | | | |
| Working Capital | $ 69 | $ 24 | $ 179 | $ – | $ (315) |
| Property, Plant and Equipment, Net | $ 4,863 | $ 4,170 | $ 3,540 | $ 3,375 | $ 3,420 |
| Total Assets | $ 6,560 | $ 5,325 | $ 5,551 | $ 4,105 | $ 4,226 |
| Net Debt(5) | $ 1,775 | $ 1,460 | $ 1,344 | $ 1,308 | $ 1,693 |
| Long-Term Debt | $ 1,844 | $ 1,484 | $ 1,523 | $ 1,308 | $ 1,378 |
| Shareholders' Equity | $ 2,348 | $ 1,904 | $ 1,460 | $ 1,798 | $ 1,459 |
| **Shares and Dividends** | | | | | |
| Common Shares Outstanding (millions) | 123.0 | 121.2 | 119.9 | 138.1 | 137.4 |
| Number of Common Shareholders | 1,372 | 1,375 | 1,394 | 1,397 | 1,527 |
| Closing Common Share Price (TSX) | $ 34.25 | $ 31.08 | $ 37.00 | $ 28.50 | $ 15.90 |
| Dividends Declared per Common Share | $ 0.30 | $ 0.30 | $ 0.30 | $ 0.30 | $ 0.30 |

Notes:

(1) Per share data is reported after dividends on preferred securities.

(2) Production and reserves are Nexen's working interest before royalties, using forecasted prices. For Nexen's reserves after royalties, using year-end prices, please refer to the Supplementary Financial Information in the Form 10-K.

(3) Natural gas is converted at 6 mcf per equivalent barrel of oil.

(4) F&D cost is defined as total capital expenditures divided by total proved reserve additions, excluding any acquisitions and dispositions. Reserve replacement cost includes acquisitions and dispositions.

(5) Net debt is defined as long-term debt less working capital.

*For more historical information, view our Statistical Supplement at www.nexeninc.com or contact Investor Relations: 406-699-5273 or investor_relations@nexeninc.com*

## HISTORICAL REVIEW (unaudited)

| Cash Flow from Operations[1] (millions of dollars) | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|
| Oil and Gas | | | | | |
| Yemen | $ 699 | $ 636 | $ 697 | $ 447 | $ 350 |
| Canada | 460 | 477 | 544 | 252 | 185 |
| United States | 190 | 285 | 321 | 147 | 135 |
| Australia | 114 | 88 | 138 | – | – |
| North Sea | – | – | – | – | 54 |
| Other Countries | 37 | 33 | 40 | 34 | (4) |
| Marketing | 45 | 71 | 36 | 19 | 25 |
| Syncrude | 129 | 110 | 102 | 86 | 36 |
| | 1,674 | 1,700 | 1,878 | 985 | 781 |
| Chemicals | 79 | 83 | 80 | 49 | 79 |
| | 1,753 | 1,783 | 1,958 | 1,034 | 860 |
| Interest and Other Corporate Items | (147) | (144) | (147) | (111) | (175) |
| Income Taxes | (223) | (216) | (242) | (143) | (85) |
| | $ 1,383 | $ 1,423 | $ 1,569 | $ 780 | $ 600 |

| Oil and Gas Cash Netback[2] ($/boe) | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|
| Producing Assets | | | | | |
| Yemen | 11.59 | 10.37 | 11.67 | 8.13 | 7.39 |
| Canada | 15.67 | 15.47 | 19.05 | 9.93 | 5.67 |
| United States | 19.30 | 26.56 | 29.73 | 13.94 | 11.70 |
| Australia | 22.66 | 22.85 | 34.13 | – | – |
| Syncrude | 21.44 | 18.75 | 18.73 | 15.05 | 7.17 |
| Company-Wide Oil and Gas | 15.00 | 15.05 | 17.82 | 10.06 | 7.50 |

Notes:

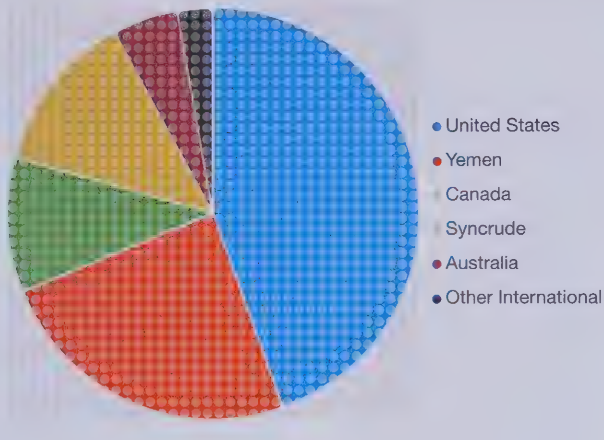
(1) Defined as cash generated from operating activities before changes in non-cash working capital.

(2) Defined as average sales price less royalties and other, operating costs, and in-country taxes in Yemen. Calculation details can be found in the Statistical Supplement on our website. Please visit www.nexeninc.com under Investor Relations.

## HISTORICAL REVIEW (unaudited)

| | 2002 | 2001 | 2000 | 1999 | 1998 |
|---|---|---|---|---|---|
| **Production Before Royalties** | | | | | |
| **Crude Oil and NGLs** (mbbls/d) | | | | | |
| Yemen | **118.0** | 118.3 | 111.9 | 107.5 | 104.7 |
| Canada | **56.3** | 58.0 | 53.9 | 48.3 | 59.2 |
| United States | **9.9** | 10.0 | 11.1 | 10.3 | 12.1 |
| Australia | **12.8** | 10.2 | 12.0 | 0.1 | – |
| Other Countries | **8.9** | 6.2 | 6.4 | 10.6 | 4.4 |
| Syncrude | **16.6** | 16.1 | 14.7 | 16.1 | 15.2 |
| | **222.5** | 218.8 | 210.0 | 192.9 | 195.6 |
| **Natural Gas** (mmcf/d) | | | | | |
| Canada | **167** | 174 | 161 | 161 | 271 |
| United States | **112** | 121 | 113 | 117 | 115 |
| North Sea | **–** | – | – | – | 34 |
| | **279** | 295 | 274 | 278 | 420 |
| Total Gross Production (mboe/d) | **269** | 268 | 256 | 239 | 266 |
| **Production After Royalties** | | | | | |
| **Crude Oil and NGLs** (mbbls/d) | | | | | |
| Yemen | **55.8** | 55.5 | 50.7 | 51.9 | 64.6 |
| Canada | **43.4** | 48.3 | 44.0 | 39.1 | 47.8 |
| United States | **8.2** | 8.3 | 9.3 | 8.6 | 10.1 |
| Australia | **10.3** | 9.6 | 12.0 | – | – |
| Other Countries | **5.2** | 5.3 | 5.4 | 8.4 | 3.8 |
| Syncrude | **16.5** | 15.5 | 12.1 | 15.8 | 13.4 |
| | **139.4** | 142.5 | 133.5 | 123.8 | 139.7 |
| **Natural Gas** (mmcf/d) | | | | | |
| Canada | **128** | 147 | 135 | 137 | 231 |
| United States | **93** | 99 | 92 | 95 | 95 |
| North Sea | **–** | – | – | – | 34 |
| | **221** | 246 | 227 | 232 | 360 |
| Total Net Production (mboe/d) | **176** | 184 | 171 | 163 | 200 |
| **Chemicals Production** (thousand short tons/year) | | | | | |
| Sodium Chlorate | **451** | 457 | 462 | 404 | 399 |
| Chlor-alkali | **410** | 383 | 395 | 330 | 340 |
| **Average Sales Price Before Royalties** | | | | | |
| **Crude Oil and NGLs** ($/bbl) | | | | | |
| WTI (US $/bbl) | **$ 26.09** | $ 25.97 | $ 30.21 | $ 19.24 | $ 14.43 |
| Yemen | **38.80** | 35.05 | 40.53 | 26.36 | 16.92 |
| Canada | **31.13** | 24.86 | 33.49 | 20.53 | 12.29 |
| United States | **38.88** | 38.35 | 44.18 | 26.51 | 19.03 |
| Australia | **40.30** | 38.71 | 41.05 | – | – |
| Other Countries | **38.96** | 37.37 | 40.12 | 23.30 | 15.23 |
| Syncrude | **40.89** | 39.90 | 44.84 | 28.12 | 20.77 |
| **Natural Gas** ($/mcf) | | | | | |
| Canada | **$ 3.57** | $ 5.02 | $ 4.38 | $ 2.46 | $ 1.94 |
| United States | **5.29** | 6.66 | 6.90 | 3.45 | 3.25 |
| North Sea | **–** | – | – | – | 5.72 |

109 mmboe Proved Reserves Added




*In 2002, we added 109 million boe of proved reserves, replacing 110% of production (102 million boe and 104%, respectively, net of dispositions). Our proved and probable reserves total 1.2 billion equivalent barrels—equal to 12 years of current annual production.*

# We are adding proved reserves,

WE'RE ADDING RESERVES IN AREAS THAT GENERATE THE STRONGEST FULL-CYCLE RETURNS.

*As the pie chart shows, 45% of our proved reserve additions in 2002 were from the Gulf of Mexico.*

New reserves from the deep-water Gunnison and Aspen projects replaced almost five years of our annual Gulf production. Although these barrels are more expensive to find and develop, we expect their netbacks to be twice our current average netback, delivering attractive rates of return.

In Yemen, we added 26 million barrels of proved reserves, replacing 60% of our production. We also added 36 million barrels of probable reserves. Our track record shows we can convert probable to proved reserves relatively quickly. And because our contract at Masila allows us to recover our costs, we achieve strong full-cycle returns from these reserves. In Canada, our increasingly mature assets were unable to replace production, resulting in a decline in total reserves at year-end and upward pressure on finding and development costs.

Our costs to find and develop new reserves increased to $13.63 per boe in 2002. Over the past five years, they have averaged a competitive $7.25 per boe. We've been investing heavily upfront for new growth that we'll see over the next four years. As a result, our F&D costs tend to be uneven from year to year. For example, in 2002, we invested more than $60 million in our synthetic crude oil project at Long Lake, yet booked only 1.5 million barrels of proved reserves for the pilot project. As Long Lake moves to the commercial development phase, we expect significant new reserve additions.

Our reserves are high quality, with 80% of our proved reserves already developed. Our proved undeveloped reserves are identifiable and have a short cycle time to development. More than one-third are in Yemen where low-risk infill and delineation drilling are expected to continue for several years. The remaining undeveloped reserves are primarily at Gunnison, which comes on-stream in 2004, and at Syncrude.

that will generate
significant value.

## PROVED AND PROBABLE RESERVE RECONCILIATION (unaudited)

### Nexen's Reserves Before Royalties, Using Forecasted Prices (1) (2)

| (oil in millions of barrels, natural gas in billions of cubic feet) | Yemen | Canada | | United States | | Australia | Other | Total | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Oil | Oil | Gas | Oil | Gas | Oil | Oil | Oil | Gas | Syncrude | mmboe |
| **Proved Reserves:** | | | | | | | | | | | |
| December 31, 2001 | 200 | 190 | 653 | 32 | 290 | 2 | 12 | 436 | 943 | 256 | 849 |
| Revisions of Previous Estimates | (4) | (4) | (14) | – | (5) | – | 1 | (7) | (19) | – | (10) |
| Purchases of Reserves in Place | – | – | 1 | – | – | – | – | – | 1 | – | – |
| Sales of Reserves in Place | – | (3) | (2) | – | – | – | (4) | (7) | (2) | – | (7) |
| Extensions and Discoveries | 30 | 12 | 36 | 35 | 82 | 6 | 2 | 85 | 118 | 14 | 119 |
| Production | (43) | (21) | (61) | (3) | (41) | (5) | (3) | (75) | (102) | (6) | (98) |
| December 31, 2002 | 183 | 174 | 613 | 64 | 326 | 3 | 8 | 432 | 939 | 264 | 853 |
| **Probable Reserves:** | | | | | | | | | | | |
| December 31, 2001 | 62 | 70 | 86 | 11 | 89 | 9 | 27 | 179 | 175 | 138 | 346 |
| Revisions of Previous Estimates | 27 | (7) | (16) | – | (8) | – | (3) | 17 | (24) | – | 13 |
| Purchases of Reserves in Place | – | – | – | – | – | – | – | – | – | – | – |
| Sales of Reserves in Place | – | (1) | (1) | – | – | – | (13) | (14) | (1) | – | (14) |
| Extensions and Discoveries | 9 | – | – | 3 | 13 | (7) | (1) | 4 | 13 | (20) | (14) |
| Production | – | – | – | – | – | – | – | – | – | – | – |
| December 31, 2002 | 98 | 62 | 69 | 14 | 94 | 2 | 10 | 186 | 163 | 118 | 331 |
| **Proved and Probable Reserves:** | | | | | | | | | | | |
| December 31, 2001 | 262 | 260 | 739 | 43 | 379 | 11 | 39 | 615 | 1,118 | 394 | 1,195 |
| Revisions of Previous Estimates | 23 | (11) | (30) | – | (13) | – | (2) | 10 | (43) | – | 3 |
| Purchases of Reserves in Place | – | – | 1 | – | – | – | – | – | 1 | – | – |
| Sales of Reserves in Place | – | (4) | (3) | – | – | – | (17) | (21) | (3) | – | (21) |
| Extensions and Discoveries | 39 | 12 | 36 | 38 | 95 | (1) | 1 | 89 | 131 | (6) | 105 |
| Production | (43) | (21) | (61) | (3) | (41) | (5) | (3) | (75) | (102) | (6) | (98) |
| December 31, 2002 | 281 | 236 | 682 | 78 | 420 | 5 | 18 | 618 | 1,102 | 382 | 1,184 |

Notes:

(1) The crude oil and natural gas prices used to determine reserve quantities were based on a mix of independent consulting firms' price forecasts, as well as management's internal view of future pricing.

| | West Texas Intermediate US \$/bbl @ Cushing, OK | Edmonton Par Cdn \$/bbl @ Edmonton, AB | U.S. Spot Gas US \$/mcf @ Henry Hub, LA | Canadian Spot Gas Cdn \$/mcf @ AECO AB |
|---|---|---|---|---|
| 2003 | 23.00 | 34.46 | 3.50 | 4.50 |
| 2004 | 23.00 | 34.46 | 3.29 | 4.21 |
| 2005 | 23.25 | 34.85 | 3.32 | 4.26 |
| 2006 | 24.00 | 36.00 | 3.43 | 4.42 |
| 2007 | 24.50 | 36.77 | 3.50 | 4.52 |
| 2008 | 25.00 | 37.54 | 3.57 | 4.63 |
| 2009 | 25.37 | 38.11 | 3.62 | 4.70 |

Crude oil and natural gas prices are escalated by 1.5% thereafter.

(2) Probable reserves are unrisked.

**Please refer to the Supplementary Financial Information in the Form 10-K for Nexen's reserves, after royalties, using year-end prices. For U.S. investors, please see the Cautionary Note on the back inside cover of this report.**

We're organized
for success,

## CORPORATE INFORMATION

### OFFICERS

**Richard M. Thomson**
Chairman of the Board

**Charles W. Fischer**
President and
Chief Executive Officer

**Marvin F. Romanow**
Executive Vice President
and Chief Financial Officer

**John B. McWilliams**
Senior Vice President,
General Counsel and Secretary

**Laurence Murphy**
Senior Vice President,
International Oil and Gas

**Douglas B. Otten**
Senior Vice President,
United States Oil and Gas

**Thomas A. Sugalski**
Senior Vice President, Chemicals

**Roger D. Thomas**
Senior Vice President,
Canadian Oil and Gas

**Nancy F. Foster**
Vice President, Human Resources
and Corporate Services

**Gary H. Nieuwenburg**
Vice President, Synthetic Crude

**Kevin J. Reinhart**
Vice President, Corporate Planning and
Business Development

**Una M. Power**
Treasurer

**Michael J. Harris**
Controller

**Rick C. Beingessner**
Assistant Secretary

**Sylvia L. Groves**
Assistant Secretary

### DIRECTORS

**Charles W. Fischer**
President and Chief Executive Officer
of Nexen Inc.

**Dennis G. Flanagan**
Retired oil executive and
director of NAL Royalty Trust

**David A. Hentschel**
Retired Chairman and
Chief Executive Officer of
Occidental Oil and Gas Corporation

**S. Barry Jackson**
Director and Executive Chairman
of Resolute Energy Inc.

**Kevin J. Jenkins**
Former President and
Chief Executive Officer and
director of The Westaim Corporation

**Thomas C. O'Neill**
Retired Chairman of PwC Consulting

**Francis M. Saville, Q.C.**
Vice Chairman and Senior Partner
of Fraser Milner Casgrain LLP,
Barristers and Solicitors

**Richard M. Thomson**
Retired banking executive and a
director of the Toronto-Dominion Bank

**John M. Willson**
Retired President and Chief Executive
Officer of Placer Dome Inc.

**Gordon R. Wittman**
Retired President, Chief Operating Officer
and a director of Dupont Canada Inc.

**Victor J. Zaleschuk**
Retired President and Chief Executive
Officer of Nexen Inc.

For more information on our officers and directors, please see Item 10 in our Form 10-K.

### CORPORATE GOVERNANCE

The Board of Directors of Nexen takes their duties and responsibilities for good corporate governance seriously. Nexen supports and conducts business according to the rules and guidelines of the Toronto and New York Stock Exchanges. We currently report our governance practices in compliance with the adopted and proposed TSX guidelines in our Proxy Statement and Information Circular.

### OPERATING ENTITIES

**Chemicals**

Nexen Chemicals Canada Limited Partnership

Nexen Chemicals U.S.A.

Nexen Química Brasil Ltda.

**Marketing**

Nexen Marketing

Nexen Marketing U.S.A. Inc.

Nexen Marketing International Ltd.

Nexen Marketing Singapore Pte Ltd.

**Canada**

Nexen Petroleum Canada

**United States**

Nexen Petroleum U.S.A. Inc.

Nexen Petroleum Offshore U.S.A. Inc.

**International**

Canadian Nexen Petroleum Yemen

Nexen Petroleum Australia Pty Limited

Nexen Petroleum Colombia Limited

Nexen Petroleum do Brasil Ltda.

Nexen Petroleum Nigeria Limited

and we're adding
value that matters.

## CORPORATE INFORMATION

### HEAD OFFICE

801 7th Avenue S.W.
Calgary, Alberta, Canada T2P 3P7
403.699.4000
www.nexeninc.com

### COMMON SHARE TRANSFER AGENT AND REGISTRARS

CIBC Mellon Trust Company
Calgary, Toronto, Montreal, Regina, Winnipeg, Vancouver and Halifax

ChaseMellon Shareholder Services
New York, NY

### STOCK SYMBOL: NXY

Toronto Stock Exchange
New York Stock Exchange

### PREFERRED SECURITIES

9.75% due 2047
Symbol: NXYPr on New York Stock Exchange

9.375% due 2048
Symbol: NXYPrA on New York Stock Exchange

Trustee: The Bank of New York, New York

### DIVIDEND REINVESTMENT PLAN

A copy of the offering circular (and for United States residents, a prospectus) and authorization form may be obtained by calling CIBC Mellon Trust Company at 1.800.387.0825 or on the internet at www.cibcmellon.ca.

### AUDITORS

Deloitte & Touche LLP
Calgary, Alberta

### INVESTOR RELATIONS CONTACT

Grant Dreger
Telephone 403.699.5273
Fax 403.699.5730
grant_dreger@nexeninc.com

### WEBSITE

Nexen's statistical supplement and other financial documents are available online at www.nexeninc.com. Hard copies may be ordered via the Investor Relations section of our website or by calling 403.699.5931.

### DUPLICATE REPORTS

Although we strive to ensure our registered shareholders receive only one copy of this annual report, duplication is unavoidable if securities are registered in multiple accounts under different names and addresses. If you received more than one copy of this report, please call CIBC Mellon at 1.800.387.0825.

### SUSTAINABILITY REPORT

Annually, Nexen produces a Sustainability Report that outlines our safety, environment and social responsibility performance. To obtain a copy, call Pam Hicks at 403.699.5297.

### FORWARD-LOOKING INFORMATION

Certain statements in this report are "forward-looking statements" within the meaning of the United States *Private Securities Litigation Reform Act of 1995,* Section 21E of the United States *Securities Exchange Act of 1934,* as amended, and Section 27A of the United States *Securities Act of 1933,* as amended. Forward-looking statements are generally identifiable by terms such as "plan", "expect", "estimate", "budget" or other similar words.The forward-looking statements are subject to known and unknown risks and uncertainties, and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied. Please read item 7 and the note regarding forward-looking statements in the Annual Report on Form 10-K for a full discussion of the risks and uncertainties associated with our business.

### CAUTIONARY NOTE TO U.S. INVESTORS

The United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to discuss only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. In this annual report, excluding the Form 10-K, we refer to "recoverable resource" and "probable reserves" which are inherently more uncertain than proved reserves. In our Form 10-K filed with the SEC, we refer only to "proved reserves".

### ANNUAL GENERAL MEETING

The Annual General and Special Meeting of Shareholders will be held on Tuesday, May 6, 2003 at 11:00 a.m. Mountain Time, in the Crystal Ballroom at the Fairmont Palliser Hotel in Calgary, Alberta, Canada.

### ABBREVIATIONS

| | |
|---|---|
| bbl | barrel |
| bbls/d | barrels of oil per day |
| bcf | billion cubic feet |
| boe | barrel of oil equivalent |
| boe/d | barrel of oil equivalent per day |
| F&D | finding and development |
| G&A | general and administrative |
| mbbls | thousand barrels |
| mmbbls | million barrels |
| mboe | thousand barrels of oil equivalent |
| mmboe | million barrels of oil equivalent |
| mcf | thousand cubic feet |
| mcf/d | thousand cubic feet per day |
| mmcf | million cubic feet |
| WTI | West Texas Intermediate |

### CONVERSIONS

Natural gas is converted at 6 mcf per equivalent barrel of oil.

### DOLLAR AMOUNTS

In Canadian dollars unless otherwise stated.

### RESOURCES AND RESERVES

Resources are generally defined as all quantities of petroleum which are estimated to be potentially recoverable from discovered and undiscovered accumulations. Reserves constitute a subset of resources that are discovered, recoverable, commercial and remaining. Nexen's reserve definitions are based on National Policy 2B for disclosure required under OSC regulations in Canada and FAS 69 for disclosure required under SEC regulations in the United States.

### FEEDBACK

We welcome your feedback on this report. Please e-mail annual_report@nexeninc.com or phone 403.699.4932.

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Every employee Every action Everywhere


Values Matter

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